CHAPTER 3 – WELL COMPLETIONS

This chapter addresses the EPA's responses to public comments on well completions in the EPA's Proposed *Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources.*

Commenters also raised issues on topics that are not covered by this chapter. Please refer to the following chapters for responses specific to those issues:

- **Chapter 1**: Source Category
- **Chapter 2**: Regulation of Methane
- **Chapter 4**: Fugitives Monitoring
- **Chapter 5**: Pumps
- **Chapter 6**: Controllers
- **Chapter 7**: Compressors
- **Chapter 8**: Equipment Leaks at Natural Gas Processing Plants
- **Chapter 9**: Liquids Unloading
- **Chapter 10**: Storage Vessels
- **Chapter 11**: Compliance
- **Chapter 12**: Regulatory Impact Analysis
- **Chapter 13**: Existing State, Local, and Federal Rules
- **Chapter 14**: Subpart OOOO
- **Chapter 15**: Miscellaneous
- **Chapter 16**: Comment Period Extension

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3.1. General Support for the Proposed Requirements

Commenter Name: Michael J. Meyers, et al., Assistant Attorneys General
Commenter Affiliation: Attorneys Generals of New York, Massachusetts, Oregon, Rhode Island, and Vermont (States)
Document Control Number: EPA-HQ-OAR-2010-0505-6940
Comment Excerpt Number: 10

Comment: The Proposed Standards for Hydraulically-Fractured Oil Well Completions are Technically Achievable and Cost Effective.

In its 2012 NSPS, EPA did not include "oil wells" in the definition of affected facilities, so those wells are currently exempt from rule's reduced emission completion, i.e., "green completion," requirements that apply to hydraulically-fractured wells. See 77 Fed. Reg. at 49,492. The 2012 NSPS rule required flaring of gas wells until January 1, 2015, at which time producers were required to use green completion equipment to separate out the gas from the water and send the gas into pipelines, where it subsequently can be sold.

EPA reasonably concluded in the Proposed Rule that hydraulically-fractured oil wells—either the completion of a newly-fractured well or re-stimulation of a previously fractured well and ongoing production—also are significant sources of both methane and VOC emissions. 80 Fed. Reg. at 56,628. EPA estimates the potential emissions from hydraulically fractured oil well completions to be 9.72 tons methane and 8.14 tons VOC per three-day completion event. Id. Although EPA's assumption of a three-day flow back duration is on the lower end of the ranges contained in several studies cited in EPA's white paper entitled "Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions and Associated Gas during Ongoing Production," EPA appropriately determined that these emissions are significant. See EPA OAQPS, Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions and Associated Gas during

Ongoing Production (2014). Furthermore, the emission figures for methane may underestimate the amount of those emissions given that aerial, or "top down" surveys of oil fields in Colorado, Utah, and elsewhere have detected much higher levels of methane than found in the "bottom up" studies in the white paper.

The Proposed Rule further shows that the same control options required for gas well completions—green completions in combination with a completion combustion device for subcategory one wells and completion combustion devices for subcategory two wells—are available and cost-effective to limit methane and VOC emissions from oil wells. 80 Fed. Reg. at 56,629-33. Although the cost effectiveness of these measures appears to vary depending upon different factors, such as the existence of nearby gas pipelines, EPA has addressed those considerations in the Proposed Rule.

Response: The EPA agrees that the proposed standards for hydraulically-fractured oil well completions are technically achievable and cost effective. We have finalized the proposed standards for hydraulically-fractured oil well completions with some additional clarifications.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 8

Comment: Oil well completions are a significant source of emissions and readily available controls can capture and reduce this pollution. We strongly support EPA's proposal to adopt standards requiring reduced emission completions ("RECs") at oil wells and recommend EPA ensure this standard is rigorously applied by:

- Removing the 300 gas-to-oil ratio exemption, given EPA's proposal to exempt wells where a separator is incapable of functioning, which serves the same purpose. Alternatively, EPA could adopt a standard based on gas production that would address a majority of emissions.

- Ensuring provisions requiring capture and beneficial use of completion emissions are rigorously applied, including a thorough consideration of beneficial use in advance of the four compliance options, 1) route to a gas line or collection system, 2) re-inject, 3) use as on-site fuel, or 4) use for another useful purpose that purchased fuel or raw material would serve.

Response: The EPA thanks the commenters for their support of the proposal to require reduced emissions completions at oil wells. The responses to the specific comments regarding the gas-to-oil ratio exemption see response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 31, and with respect to beneficial use provisions see response to DCN EPA-HQ-OAR-2010-0505-5288, Excerpt 6.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 58

Comment: EPA proposes to require reduced emission completions at hydraulically fractured oil wells. Oil well completions are a significant source of emissions, likely responsible for over 100,000 tons of methane emissions annually. Moreover, the same technologies available to reduce emissions at gas wells can mitigate oil well completions emissions. Capture and beneficial use of natural gas that would otherwise be wasted can significantly offset costs associated with deploying these technologies. Accordingly, we strongly support EPA's proposal to extend reduced emissions completion (REC) requirements to hydraulically fractured oil wells.

Response: The EPA thanks the commenters for their support of the standards for reduced emissions completions at oil wells. We have finalized the proposed requirements with some additional clarifications.

Commenter Name: P. DeMarco
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2010-0505-5167
Comment Excerpt Number: 11

Comment: Require Reduced Emission Completions (REC), also known as "green completion," to reduce methane and other VOC leaks for all wells, not only gas wells. RECs and green completions refer to technologies that capture methane and other gases at the well head during and after well completion and avoid their release into the atmosphere.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7062, Excerpt 58.

Commenter Name: Richard Eidlin, Vice President, Policy and Campaigns
Commenter Affiliation: American Sustainable Business Council (ASBC)
Document Control Number: EPA-HQ-OAR-2010-0505-6916
Comment Excerpt Number: 4

Comment: We also support other provisions of the revised rule including the extension of standards to additional midstream sources to reduce methane emissions at transmission and storage segments and limits on venting gas during oil well completion.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7062, Excerpt 58.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:00 AM - 11:55 AM; Public Hearing #2 - Pittsburgh, Pennsylvania
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 14

Comment Excerpt: We are also pleased that the agency has extended the standard to downstream sources in the transmission and storage segments and addressed the harmful practice venting during oil well completions.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7062, Excerpt 58.

3.2 Best System of Emission Reduction

Commenter Name: Karen Sjoberg, Chairperson
Commenter Affiliation: Citizens for Clean Air (CCA)
Document Control Number: EPA-HQ-OAR-2010-0505-5288
Comment Excerpt Number: 6

Comment: However source operators should be required to capture gas for sale or for beneficial use on site, rather than route it to a completion combustion device, unless it is technologically infeasible to do so. Any combustion device should have a control efficiency of 95% or greater.

Response: The comment reflects the EPA's proposal for subcategory 1 wells, which the EPA is finalizing. In the final rule, operators of Subcategory 1 wells must capture emissions during the separation flowback period of each well completion, and direct the captured emissions into a gas flow line or collection system, re-inject into the well or another well, use as an on-site fuel source, or use for another useful purpose that a purchased fuel or raw material would serve. Only if none of these options are technically feasible would captured emissions be routed to a completion combustion device, the final rule requires that owner/operator keep records explaining why routing the collected gas to one of the four options was not technically feasible.

In summary, under the final rule, combustion is viewed as a last resort to be used only after serious evaluation of the feasibility of routing the gas as described above for REC. With regard to control efficiency requirements for completion combustion devices, we note that flowback periods following hydraulic fracturing are relatively short – just a few days – and these short periods are not compatible with requirements for performance testing during operation of the emissions source. This is in contrast to control devices that are used for other sources covered by the NSPS such as wet seal centrifugal compressors and storage vessels.

Commenter Name: I. Snow
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2010-0505-5411
Comment Excerpt Number: 4

Comment: In reading the rule, I found it to be weak in the area of regulations on well completions. For subcategory 1 wells, green completion is only a solution in equal combination with flaring. And particularly for subcategory 2 wells, the rule frames flaring as both a positive and major solution for emissions. However, while better for methane emission amounts, flaring directly creates carbon dioxide as a product. Additionally, flaring is a process which results in no useful work, and is therefore wasteful of gas that might be captured and used.

As a major facet of The President's Climate Action Plan from 2013, this rule needs to be aligned with that plan, where the primary goal is "a broad-based plan to cut the carbon pollution that causes climate change and affects public health". This means that flaring does not help accomplish the overarching goal of cutting carbon emissions, but rather displaces emissions and contributes to the problem which the Climate Action Plan attempts to mitigate.

I believe the rule should be changed to emphasize REC's and capture of vented gas as solutions, and frame flaring as a last resort, rather than a technique to be used equal in combination or as the only solution.

Supporting cleaner methods (and possibly creating incentives either positive or punitive to make them more economical) will maximize environmental benefits. It will also drive economic diffusion and growth of companies that produce the technologies, making them cost effective over time.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5288, Excerpt 6.

Commenter Name: T. Bacci
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2010-0505-6471
Comment Excerpt Number: 8

Comment: We urge you to improve the proposed rules to include: Requiring oil and gas companies to use or bring to market captured gas, rather than flare it, unless truly extraordinary circumstances make flaring unavoidable.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5288, Excerpt 6.

Commenter Name: S. Hathaway
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2010-0505-6473
Comment Excerpt Number: 7

Comment: We urge you, even knowing that it's futile, to improve the proposed weak rules to include:

Requiring oil and gas companies to use or bring to market captured gas, rather than flare it, unless truly extraordinary circumstances make flaring unavoidable (but they'll claim truly extraordinary circumstances in any case, and you'll go right along with them).

Response: See response to DCN EPA-HQ-OAR-2010-0505-5288, Excerpt 6.

Commenter Name: Terry Lansdell, Program Director
Commenter Affiliation: Clean Air Carolina
Document Control Number: EPA-HQ-OAR-2010-0505-7241
Comment Excerpt Number: 7

Comment: Requiring oil and gas companies to use or bring to market captured gas, rather than flare it, unless truly extraordinary circumstances make flaring unavoidable.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5288, Excerpt 6.

Commenter Name: P. DeMarco
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2010-0505-5167
Comment Excerpt Number: 15

Comment: Limit venting and flaring gas associated with oil production and ensure that all gas is captured or used on-site.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5288, Excerpt 6.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:05 AM - 8:00 PM; Public Hearing #1 - Pittsburgh, Pennsylvania
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338-1
Comment Excerpt Number: 185

Comment: In many instances, the proposed standard would allow source operators either to capture gas for sale or for beneficial use on-site or to direct the captured gas to a completion combustion device such as a flare. From both an environmental and a waste-of-wind standpoint the form option is always preferable to the latter. EPA must specify the use of completion control devices shall be permitted only where it's technically infeasible to capture the gas for sale, or on-site use, or to use zero-emitting equipment. Such devices must also have a 95 percent combustion efficiency or greater.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5288, Excerpt 6.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:00 AM - 11:55 AM; Public Hearing #2 - Pittsburgh, Pennsylvania

Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338-2
Comment Excerpt Number: 24

Comment: And, again, we also hope that they will specify that the use of completion control devices or flaring, will be permitted only where it is technically infeasible or impossible to capture the gas or to use zero emitting equipment.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5288, Excerpt 6.

Commenter Name: Ben Shepperd
Commenter Affiliation: Permian Basin Petroleum Association
Document Control Number: EPA-HQ-OAR-2010-0505-6849
Comment Excerpt Number: 80

Comment: Should EPA move forward with REC requirements for oil wells, flaring should be allowed as an option. EPA incorrectly assumes that gas sales lines are readily available to which gas can be separated and sent. Often the sales lines are under construction or multi-well portfolios are being drilled and gas volumes measured to best design the gathering system to accommodate the gas composition and volume. EPA has proposed two subcategories for wells, subcategory 1 which includes non-wildcat and non-delineation wells, or subcategory 2, which includes wildcat and delineation wells. These definitions are loose and make a number of assumptions about the consistency of geologic formations and the salability of the gas before it can even be analyzed. Instead of requiring that an oil well be categorized, the PBPA recommends that flaring simply be allowed as a REC option. The subcategory classification system for oil wells should be withdrawn.

Response: The EPA disagrees with the commenters in that combustion should be an equal option to performing a REC. The intent of the rule is to minimize venting and combustion where possible. Therefore, operators have four options to use recovered gas for a useful purpose that must be evaluated prior to flaring. The final rule requires that captured emissions must be directed from the separator into a gas flow line or collection system, re-injected into the well or another well, used as an on-site fuel source, or used for another useful purpose that a purchased fuel or raw material would serve. Only if any or all of these options are technically infeasible would captured emissions be routed to a completion combustion device.

Commenter Name: Ben Shepperd
Commenter Affiliation: Permian Basin Petroleum Association
Document Control Number: EPA-HQ-OAR-2010-0505-6849
Comment Excerpt Number: 83

Comment: 1. The REC requirements for oil wells should be withdrawn.

2. Alternatively, should EPA move forward with REC requirements for oil wells, flaring should be allowed as an option.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6849, Excerpt 80.

Commenter Name: Cyrus Reed, Conservation Director
Commenter Affiliation: Lone Star Chapter, Sierra Club
Document Control Number: EPA-HQ-OAR-2010-0505-5418
Comment Excerpt Number: 11

Comment: It is critical that EPA make clear that capturing gas and routing it to a process or to a pipeline for eventual sale is the first-order emissions control method, in contrast to flaring. More flaring is not needed in Texas, where we already combust (and hence waste) too much gas. Moreover, while preferable to venting, flaring is often done in ways that do not fully combust the product, leading to greater emissions of methane, VOCs, and air toxics. This practice also impacting nighttime skies and tarnishes the viewsheds and air quality of local communities. Gas should therefore be captured and routed to a process, rather than flared, unless there is a safety risk or there is no other technological option available.

Where gas must be flared, the rule should establish a minimum destruction efficiency of 98 percent, the recommendation of the Center for Sustainable Shale Development (CSSD) in a recent report. In this study, the CSSD recommends that when flaring is permitted during well completion, re-completions or workovers, the following requirements must apply:

• Raised/elevated flares or engineered combustion device with a reliable continuous ignition source.

• 98% destruction efficiency.

• Development well: flaring no more than 14-days (for life of well).

• Exploratory/Extension wells: flaring no more than 30-days (for life of well). No visible emissions from flares except for periods not to exceed a total of five minutes during any two consecutive hours.

Response: The EPA agrees in part with the commenter, but does not agree with all of the suggestions. In the final rule, operators of Subcategory 1 wells must capture emissions during the separation flowback period of each well completion a direct the captured emissions into a gas flow line or collection system, re-inject into the well or another well, use as an on-site fuel source, or use for another useful purpose that a purchased fuel or raw material would serve. In the final rule, operators of subcategory 1 wells must capture emissions during the flowback period of each well completion and direct the separator into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an on-site fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve. Only if none of these options are technically feasible would captured emissions be routed to a completion combustion device.

It is uncertain, and we have no data showing, that overall 98 percent mass destruction of VOC and methane from combustion completion devices is achievable. Note that the control efficiency in the BSER analysis takes into consideration capture and destruction efficiencies, not destruction efficiency alone.

The commenter's suggestion that we allow flaring for 14 days is not consistent with our BSER analysis for well completions of subcategory 1 wells, which shows that REC is BSER unless it is technically infeasible. With respect to subcategory 2 and low pressure wells, the final rule requires combustion. However, 14 days is longer than our estimated duration of a well completion event which is 3-10 days; we therefore reject setting such time period for our requirement but instead impose standards that cover the duration of flowback.

Commenter Name: Camilla Feibelman
Commenter Affiliation: Rio Grande Chapter of the Sierra Club
Document Control Number: EPA-HQ-OAR-2010-0505-6895
Comment Excerpt Number: 15

Comment: It is critical that EPA make clear that capturing gas and routing it to a process or to a pipeline for eventual sale is the first-order emissions control method, in contrast to flaring. More flaring is not needed in New Mexico, where we already combust (and hence waste) too much gas. Moreover, while preferable to venting, flaring is often done in ways that do not fully combust the product, leading to greater emissions of methane, VOCs, and air toxics. This practice also impacting nighttime skies and tarnishes the viewsheds and air quality of local communities. Gas should therefore be captured and routed to a process, rather than flared, unless there is a safety risk or there is no other technological option available.

Where gas must be flared, the rule should establish a minimum destruction efficiency of 98 percent, the recommendation of the Center for Sustainable Shale Development (CSSD) in a recent report. In this study, the CSSD recommends that when flaring is permitted during well completion, re-completions or workovers, the following requirements must apply:

• Raised/elevated flares or engineered combustion device with a reliable continuous ignition source.

• 98% destruction efficiency.

• Development well: flaring no more than 14-days (for life of well).

• Exploratory/Extension wells: flaring no more than 30-days (for life of well).

No visible emissions from flares except for periods not to exceed a total of five minutes during any two consecutive hours.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 11.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 33

Comment: We also recommend that delaying completions be a viable option regarding gathering line availability with consideration to flaring. Those living and attending school within measurable feet of well sites are deserving of more stringent requirements since there has not yet been a determination for health based setback distances regarding well pad placement. When the operators choose to knowingly site well sites measurable feet from our homes and schools, in essence they are proclaiming that they are not giving appropriate consideration to nearby families and students, therefore they must be regulated into doing so in order to adequately protect public health and safety.

Response: Delay alone does not reduce emissions, unless, during that delay, a gathering line is constructed or otherwise becomes available, or on-site use or other destination for the gas (other than venting) would provide the owner or operator the ability to perform a REC [see the requirements at §60.5375a(a)(1)(ii)]. Further, it is not clear whether and when a gathering line would be available in any given situation, and what the potential cost impacts would be to the owner or operator. In cases where the operator documents that a REC is technically infeasible, emissions are required to be controlled using combustion. The NSPS requires control of emissions through REC, with combustion being allowed only as a last resort in cases where REC is technically infeasible. The EPA believes that the NSPS provides for responsible oil and natural gas production without compromising the owner or operator's ability to get the oil and gas to market. For the reasons stated above, the EPA disagrees with the commenters in that delaying completions is a viable option to address emissions from well completions.

Commenter Name: Ben Shepperd
Commenter Affiliation: Permian Basin Petroleum Association
Document Control Number: EPA-HQ-OAR-2010-0505-6849
Comment Excerpt Number: 79

Comment: The PBPA requests that the Reduced Emission Completion (the "REC") requirements for oil wells be withdrawn. Gas volumes from oil well flowback is much smaller relative to gas wells. EPA has failed to illustrate that the absence of REC requirements contributes significantly to air emissions. As a matter of normal operating procedure, gas from oil well flowback events is very rarely vented to the atmosphere. Due to safety concerns, gas produced during flowback is sent to a flare or other combustion device to eliminate explosion hazards. Additionally the Permian Basin often produces oil where hydrogen sulfide is present. Hydrogen sulfide is lethal when inhaled, subsequently it is essential that it be combusted if not immediately put on a sales line. The United States Occupational Safety and Hazard Administration states a level of H_2S gas at or above 100 ppm is Immediately Dangerous to Life and Health (IDLH). It is unnecessary and costly for the EPA to place federal notification, reporting, photography and record keeping requirements for Reduced Emission Completions. The EPA states in the preamble that "the use of traditional combustion control devices present local emissions impacts" without elaborating on how those impacts exist in rural areas where 98% of the wells occur.

Response: The EPA agrees with the commenter that well completion emissions from oil wells is lower than gas wells, however, we disagree that these emissions do not warrant regulation. Data available on oil well completions indicate that the emissions average 999 Mcf of natural gas or 9.72 tons of methane and 8.14 tons of VOC per completion event and the emissions are cost effective to control by a REC. These emissions are currently flared, which result in emissions of NOx and other pollutants. To minimize these emissions from flaring, the rule would require a REC unless it is not technically feasible. With respect to hydrogen sulfide content in the gas, this is the type of circumstance that might render a REC technically infeasible and as such would not be required. However, rule requirements justifying the combustion of emissions are warranted due to the intent of the rule to minimize venting and combustion of natural gas emissions. Whether in a rural environment or not, the secondary impacts of combustion are a concern and are considered when developing regulations.

Commenter Name: Maria Pica Karp, Vice President and General Manager, Chevron Government Affairs
Commenter Affiliation: Chevron U.S.A. Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6929
Comment Excerpt Number: 13

Comment: <u>Exceptions:</u> When general knowledge of field characteristics indicates a Reduced Emissions Completion (REC) is not feasible due to lack or quality of gas, operators should not be required to bring a separator out on site and record every attempt to connect. This will needlessly increase cost and compliance burden without reducing emissions.

Response: See section VI.E.1 of the preamble to the final rule for a discussion of this issue.

Commenter Name: Michael Turner, Senior Vice President, Onshore
Commenter Affiliation: Hess Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6960
Comment Excerpt Number: 5

Comment: Hess does not support the adoption of the "reduced emissions completions" ("REC" or "green completions") for oil wells rule as proposed, which in practice for some operators amounts to a "zero flaring" rule during completions. Accordingly, Hess proposes that EPA make changes to the Proposed OOOOa Rule to allow flaring in certain circumstances in accordance with state regulations. Specifically, Hess proposes: 1) a 14-day exemption from the requirement that all natural gas from a separator be routed to a gas flow line or collection system; and 2) that EPA accept state flaring regulations as determinative of "technical infeasibility."

Hess encourages EPA to give greater credence to state regulatory agencies regarding the determination of technical feasibility of gas capture from hydraulically fractured oil wells to accommodate significant differences between state regulatory schemes and infrastructure availability. As EPA understands, given its consultation of the Colorado and Wyoming regulations in evaluating its own regulatory options, that state agencies have unique experience in regulating oil and gas operations. North Dakota is not only the country's second leading oil producer (behind only Texas), but it has unique geological, geographical, weather, and infrastructure concerns. NDIC and NDDoH understand the Bakken geology and state infrastructure constraints better than either EPA or other state agencies (Colorado and Wyoming included) and are better suited to determine the technical feasibility of various gas capture approaches in North Dakota. EPA should defer to those states with robust regulatory schemes, like North Dakota, that effectively reduce both venting and flaring emissions.

Hess appreciates that EPA strives to regulate in a way that "complement[s], not complicate[s], existing state requirements." In that spirit, Hess encourages EPA to allow a more flexible approach to setting performance standards for oil well completions given the differences in state geologies, geographies, and infrastructure limitations. The Proposed OOOOa Rule for oil well completions constitutes a one-size-fits-all approach that disregards the unique characteristics of North Dakota's Bakken shale play. Based in part on its review of regulations promulgated in Colorado and Wyoming, EPA proposed to allow unrestricted gas venting during the "initial flowback stage" and require the use of a flare or other combustion device during the "separation flowback stage." EPA proposes that after a separator is attached operators must route all salable gas to a flow line and that combustion is only permitted when it is technically infeasible for an owner/operator to route gas to a flow line, re-inject the gas, or use it in a beneficial manner. We have significant concerns that the Proposed OOOOa Rule, if finalized in its current form, would conflict with North Dakota's current regulations which are tailored to the particular challenges of Bakken oil producers. Current North Dakota regulations, although different in approach, provide for optimal environmental protection while accounting for unique state challenges.

The NDIC's Department of Mineral Resources is responsible for regulating oil and gas operations in North Dakota. On July 1, 2014, it issued Order No. 24665 to address reductions in natural gas flaring from Bakken shale play oil production. The order was the product of an NDIC effort to "reduce the flared volume of gas, reduce the number of wells flaring, and reduce the duration of flaring from wells." The NDIC took extensive written testimony on the operations of Bakken wells, methods to reduce flaring, and constraints on natural gas gathering infrastructure endemic to the area. The resulting regulations are a balanced and environmentally-effective scheme for reducing the venting and flaring of gas with numeric gas capture goals phased in over time. Order No. 24665 (as subsequently revised) currently requires oil producers to capture 77 percent of gas from their statewide operations; increasing to 85 percent on November 1, 2016. By November 1, 2020, oil producers are required to attain 91 percent of all gas with the potential for a further increase to 95 percent after that date. As described above, the NDIC issued its Order after finding that:

Total gas plant capacity in North Dakota exceeds total gas production in the state although many bottlenecks exist in the current gas gathering infrastructure due to the high liquid content of the gas, the prolific volumes of oil and gas during initial production, increasing pipeline pressure that requires installation of additional compressors, and in some cases undersized pipe. Most operators are prudently attempting to connect their wells to a gas gathering system, but due to many aforementioned constraints in the gas gathering systems, much of the gas is not processed.

Although termed "goals," NDIC's gas capture targets are enforceable against crude oil and natural gas producers. Pursuant to NDIC implementing guidance, if an operator fails to meet the statewide capture goal in effect at the time, but manages to capture at least 60 percent of their wells' gas, production capacity at those wells will be limited to 200 barrels per day. If gas capture falls below 60 percent, production will be curtailed to 100 barrels per day. If the operator fails to adhere to these production restrictions, they can be fined up to $12,500 per well per day. These production constraints, backed by daily fines, are enforceable limits that create significant financial incentives for operators to meet NDIC's gas capture goals.

To meet these enforceable "goals," oil producers must submit a individualized Gas Capture Plans for each well pad as a condition to obtaining a permit to drill. Gas Capture Plans provide estimates of crude oil and natural gas production from any new wells over the first several months of production. Oil producers must indicate how existing infrastructure (or infrastructure estimated to be on-line by the time production begins) can manage the crude oil and natural gas produced from the well. The Gas Capture Plans include maps and other detailed information about third party gas gathering lines and compressor stations that will be used to collect and transport gas from oil wells, such as the compression capacity, anticipated throughput after initial flowback, and anticipated capacity on the date of first sales. The anticipated throughput provides the NDIC with an understanding of how much gas can actually be processed through the gathering system, and therefore, the amount of gas that will either be processed for beneficial use on-site or flared.

Oil producers must also identify the means by which they will reduce flaring to meet gas capture goals, providing each producer with significant flexibility to adapt to site conditions, such as limited access to electricity or gathering capacity limitations. Hess, for example, currently deploys 16 mobile natural gas refrigeration units manufactured by GTUIT. These units extract and process natural gas liquids for beneficial use or sale that would otherwise by flared. Each unit can process up to 10 million cubic feet per day of gas and produce up to 35,000 gallons of natural gas liquids per day. Natural gas generators can also be used to provide electricity to well pads in remote areas.

The NDIC regulations, including numeric gas capture goals and individual well pad gas capture plans, offer a different approach than that outlined in the Proposed OOOOa Rule, requiring producers to maximize gas capture while providing the flexibility needed to cope with the unusual challenges present at individual well pads. In fact, Hess suggests that NDIC's enforceable gas capture goals make them more stringent than EPA's proposed operational standards. In contrast to EPA's proposed operational standard - gas should be routed to a sales line unless "technically infeasible"- NDIC's gas capture goals are numeric standards based on extensive and informed study of the Bakken's unique geology and the developing pipeline and electricity infrastructure in the area. The North Dakota numeric standards are not only scheduled to further reduce emissions over time, but they are objectively measurable and enforceable. This alone qualifies them as being more stringent, and therefore preferable, to the operational standards proposed by EPA.

The NDIC's numeric standards go further, however, in that they dispense with the proposed rule's "all or nothing" approach: EPA assumes that either gas is vented upon initial flowback or "all salable quality gas" may be routed "from the separator to a flow line or collection system ... " Flaring is only allowed under the Proposed NSPS OOOOa Rule when an operator establishes that it is "technically infeasible" to re-inject all of the excess gas into a well or somehow use all of the excess gas for another useful purpose. When it is technically infeasible to capture, re-inject, or use all of the natural gas, EPA's proposed rule would allow flaring without any other limitations. NDIC's regulations do not. Instead, its numeric standards give crude oil producers flexibility to manage natural gas flows depending on specific site conditions so long as they comply with the state's gas capture rules. This flexibility has incentivized and allowed crude oil producers such as Hess to establish innovative solutions to reduce flaring, such as use of the mobile GTUIT units to strip out natural gas liquids.

Although some commenters may argue that North Dakota's current gas capture target of 77 percent (increasing to 90 percent by October 1, 2020) could be higher, these targets are based on NDIC's assessment of what is technically feasible for all North Dakota producers. Hess was unable to find any record evidence showing that EPA either performed its own assessment of what is technically feasible in the Bakken or that the Proposed OOOOa Rule will achieve greater rates of gas capture in practice. Although EPA's Background Technical Support Document estimates that reduced emission completions can reduce gas emissions by 90 percent, this is based on 2011 data from four Natural Gas STAR presentations involving capture from gas wells, none of which were in North Dakota ("May 2011 ICF Memo"). The May 2011 ICF Memo estimates an average gas capture of 90 percent through reduced emission completions (with actual capture ranging from 61.3 percent to 99.9 percent) based on data from gas wells from the Jonah Field in Wyoming; the Denver-Julesburg Basin in Colorado; Cook Inlet, Alaska; and the Piceance Basin in Colorado. These comparisons are of limited value in understanding gas capture feasibility from crude oil wells in the Bakken. EPA has already acknowledged that the Bakken is "a formation that possesses unique characteristics both with regard to reservoir and formation characteristics, gas composition and the lack of infrastructure due to rapid development of the industry in the area." There appears to be no record basis to conclude that the proposed NSPS would actually reduce emissions from the Bakken Shale play more than NDIC's gas capture goals, much less by 90 percent as claimed in the May 2011 ICF Memo. The NDIC gas capture program represents the best system of emission reduction that is technically feasible for Bakken crude oil wells.

Accordingly, EPA should explicitly state that where there is a state program that controls flaring from oil wells during completion, such programs will be accepted by EPA as a determination of the "technical feasibility" of gas capture in those states.

Response: The EPA agrees with the commenter that states have significant experience in dealing with oil and gas industry emission reduction strategies within their jurisdiction and that each state is in the best position to address the unique characteristics of fields and reservoirs in that state. In development of the rule The EPA has made specific effort to minimize conflict with any state requirements. In fact as noted by the commenter, where possible, the final requirements are similar to state programs. It also should be noted, that the NSPS affects only new sources and only completions, and does not regulate emissions from production. The North Dakota requirements as described by the commenter address new and existing facilities and include completions and production activities. As the commenter notes, oil producers must reduce flaring to meet gas capture goals. Therefore, gas capture during production is the companion piece to the flaring component of the North Dakota requirements. In addition, the North Dakota gas capture goals are a system-based approach, with requirements at the operator level from well completion through production, not the unit level requirement for well completion and therefore do not correspond with BSER for well completion under the NSPS. However, we believe implementation of the NSPS the requirements will contribute to meeting the North Dakota goals for gas capture.

The commenter misinterprets the technical infeasibility requirement in the rule. Under 60.5375a, operators must capture emissions during the separation flowback period of each well completion, unless it is technically infeasible to do so. The owner or operator must direct captured emissions from the separator into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an on-site fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve. The rule provision for use of captured gas for “any useful purpose” provides flexibility which could include processes described by the commenter such as mobile natural gas refrigeration units or natural gas generators for onsite electricity. Under the final rule, only if these options are not technically feasible (which may include the lack of infrastructure and gathering line concerns noted by the commenter) would captured emissions be routed to a completion combustion device.

As noted above, the final rule requires the use of a REC and the disposition of the gas by routing to one of the four beneficial uses prior to using combustion for destruction of the pollutants. Based on available information on the North Dakota requirements, the regulations are not comparable as they do not require a case by case analysis for technical infeasibility for each of the four recovered and beneficial uses prior to flaring. Therefore, a technical infeasibility determination under the North Dakota requirements would not directly satisfy the NSPS requirement. Therefore, a state determination of technical infeasibility would not be considered in lieu of a determination under the NSPS requirements, However, any applicable documentation that is used for a state determination would be acceptable under a determination for the NSPS, provided the operator addresses each of the NSPS requirements.

With respect to the commenters suggestion for a 14-day exemption from REC requirements see the response to comment DCN EPA-HQ-OAR-2010-0505-6960, Excerpt 15.

Commenter Name: Michael Turner, Senior Vice President, Onshore
Commenter Affiliation: Hess Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6960
Comment Excerpt Number: 15

Comment: In order to ensure consistency with the North Dakota regulations and gas capture program, Hess proposes a 14-day exemption for flaring during well completion, whether the well is in "initial flowback" or "separation flowback" as those terms are used in the Proposed OOOOa Rule. For Hess, EPA's proposed distinction between "initial flowback" and "separation flowback" is a distinction without a difference. Many operators in the Bakken, including Hess, may immediately route well production volumes to a "flowback separator" before utilizing more permanent separation equipment. EPA's proposed regulations, however, fail to define "separator" and do not distinguish between flowback and production separation. Moreover, some well sites do not have clear initial and separation flowback stages like gas wells. In its gas capture rule, North Dakota recognizes the difficulty of capturing 100 percent of the high-volume natural gas production during well completion and accordingly allows 14 days of flared gas to be excluded from gas capture calculations. Likewise, EPA should offer more flexibility to meet the control requirements by allowing a grace period of at least 14 days during which operators may route emissions to a flare during either the "initial" or "separation" flowback periods.

Response: The 14-day flaring suggested by the commenter is not consistent with our BSER analysis for well completions of subcategory 1 wells, which shows that REC is BSER where a separator can function. With respect to subcategory 2 and low pressure wells, the final rule requires combustion. However, 14 days is longer than our estimated duration of a well completion event which is 3-10 days; we therefore reject setting such time period for our requirement but instead impose standards that cover the duration of a well completion..

Commenter Name: Jack Dalrymple, Chairman, Governor, Wayne Stenehjem, Attorney General and Doug Goehring, Agriculture Commissioner
Commenter Affiliation: North Dakota Industrial Commission (NDIC)
Document Control Number: EPA-HQ-OAR-2010-0505-6977
Comment Excerpt Number: 3

Comment: Wildcat well, delineation well, non-wildcat well, non-delineation well, non-wildcat low pressure well, non-delineation low pressure well: North Dakota regulations for gas capture clearly define the first well in the spacing unit as exempt from the gas capture and production requirements imposed by NDIC Order No. 24665. The proposed rule defines two subcategories of hydraulically fractured wells: (1) Non-exploratory and non-delineation wells, also known as development wells; and (2) exploratory (also known as wildcat wells) and delineation wells. An exploratory well is the first well drilled to determine the presence of a producing reservoir and the well's commercial viability. A delineation well is a well drilled to determine the boundary of a field or producing reservoir. This results in a clear conflict between the proposed rule which contains well definitions that are logical for conventional resource development, but not for unconventional development and existing North Dakota rules which contain a clearly defined standard.

Response: The NSPS rule definitions for exploratory and delineation wells are solely for the purpose of requirements under the NSPS rule and do not affect definitions under any other state or local regulations.

Commenter Name: Jill Morrison
Commenter Affiliation: Powder River Basin Resource Council
Document Control Number: EPA-HQ-OAR-2010-0505-7240
Comment Excerpt Number: 5

Comment: Regarding green completions we recommend and request that EPA remove the "technical feasibility" exception. We believe it invites poor design or even creates a loophole that encourages a deliberate "designing away" of the regulatory applicability. If the well cannot be completed with reduced emissions, it shouldn't be drilled in the first place.

Response: Please see section VI.E.2 of the preamble to the final rule for a discussion of the reason for the technical infeasibility exemption. In the final rule, we have strengthened the documentation and recordkeeping requirements in order to claim the technical infeasibility exemption, and we continue to believe that there are instances where performing a REC is technically infeasible and the rule must provide relief in those instances.

Commenter Name: Shawn Bennett, Executive Vice President
Commenter Affiliation: Ohio Oil & Gas Association (OOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6921
Comment Excerpt Number: 11

Comment: RECs or "Green Completions" for oil wells are not the same as those for gas wells. For oil wells, many times it is difficult to distinguish between initial flowback and separation flowback stages. Thus, it would be very difficult to determine when the REC requirements would begin under the proposed rules. In addition, the cost-effectiveness for RECs on oil wells is driven by the price and volume of oil produced. The requirement for oil well RECs may render many lower production wells uneconomical. The Association recommends that EPA conduct a detailed economic analysis on the cost-effectiveness of oil well RECs using current market rates for oil. Using that analysis, EPA should exempt low-production wells from the REC requirements.

Response: We believe that the provisions regarding the use of a separator in the final rule addresses the commenter’s concern with distinguishing between the initial flowback stage and separation flowback stage.

Section 111 requires that we consider costs in evaluating control options. In evaluating control costs, the EPA adhered to the guidance from the D.C. Circuit in a string of case law, which provided various formulations of the cost standard-" exorbitant," "greater than the industry could bear and survive," "excessive," and "unreasonable." *See* 80 FR 56593, 56616. We find the economic analysis recommended by the commenter (i.e., whether well production would be uneconomical as a result of the requirement) inconsistent with the cost standard established by these case law.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 65

Comment: Most of the cost to flare flowback gases is for rental of the separator equipment, mileage, labor to install and remove equipment, and additional personnel to operate the specialty equipment. In public comments on the EPA White Paper on Hydraulically Fractured Oil Wells, IPANM members estimated the cost for flaring oil well completions as up to $10,000 per day. API agrees that this is a more reasonable typical cost to rent, transport, install, operate and remove separator and flare equipment. In addition, flowback can range from one day to more than 30 days, with 3 to 7 days being most typical.

Response: The EPA has reviewed the public comment on the EPA White Paper on Hydraulically Fractured Oil Wells the commenter referenced. The public comment does not provide sufficient detail to evaluate this cost data point. See the TSD to the final rule for additional cost information.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 165

Comment: The cost of a completion combustion device was estimated to be $3,723 in 2012$ based on the 2012 NSPS by EPA. Based on public comments to EPA from the Independent Producers Association of New Mexico (IPANM) on the Methane White Papers, members estimated the cost for flaring oil well completions at over $10,000. This is believed to be a more reasonable cost to rent, transport, install, operate and remove separator and flare equipment.

Response: Please see response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 65.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 68

Comment: The cost analysis for REC requirements is incomplete or incorrect. For example, in its proposed rule, EPA's analysis of REC costs assumes a range of $700-$6,500, lasting for an average of three days. EPA assumes an oil well REC will cost on average $13,586, taking into account gas savings. 80 Fed. Reg. at 56,629. EPA's numerous assumptions to reach this conclusion are flawed and ignore actual operator experience. In our members' experience, actual costs will be much higher.

We also question the rule's analysis of the oil well completion emission benefits. In its white paper analysis of oil well completions, EPA states that methane is 46.732 percent of the volume of gas produced during a well completion. Based on surveys of operators, this number is highly inaccurate (see table below). Our analysis suggests 40 to 80 percent is a more representative range for methane, with many basins producing gas that is over 60 percent methane. It also is important to note the remaining gas volume is not entirely VOCs. Gases like ethane, carbon dioxide, and nitrogen can make up significant volumes of produced gas. In many cases, VOC emissions are likely 10 to 30 percent of the total volume. These differences in gas composition will dramatically affect EPA's cost and benefit analysis. EPA's flawed assumptions about the value of natural gas prices and therefore the value of recovered product will be compounded by the inaccurate assumptions about gas compositions. The end result is an inflated benefit calculation that assumes much higher recovery rates of higher-value VOCs than methane.

Oil Well Completion Data

	DJ Basin	**Williston Basin**	**Powder River Basin**	**Permian Basin**
Days to complete (flowback)	2 to 7	2 to 9	21 to 28	3 to 5
Additional green completion cost per day ($/day)	$2,000-$7,200	$3,500-$10,800	$8,400	$4,500
Average volume of gas produced during completion (MCF/day)	1,500-3,000 MCF	300-2,500 MCF	100-1,500 MCF	500-1000
Average percent gas currently flared during completion	50-80 percent	50-80 percent	90-100 percent	90-95 percent
Average percent gas currently sold during completion	20-50 percent	20-50 percent	0-10 percent	0 percent

Average percent gas currently vented during completion*	< 1 percent	< 1 percent	< 1 percent	5-10 percent
Methane gas composition percent	40-80 percent	50-70 percent	70-80 percent	75 percent
VOC gas composition percent**	10-30 percent	10-30 percent	10-20 percent	12 percent

Also of note is the high variability of well flowback times and costs per green completion. A one-size-fits-all cost analysis will almost certainly fail to capture the highly variable nature of well completion operations. Small operators also tend to be on the high end of completion costs, and typically conduct completions less frequently. Generally, small operators lack the purchasing power to get the discounted prices service companies offer to larger operators. Therefore a one-size-fits-all cost estimate would likely not adequately represent the cost burden faced by small operators. In order to demonstrate the REC requirements being proposed would be cost-effective, the final rule's economic analysis must consider these points.

Response: We appreciate the commenter submitting the data provided in their comment. However, the commenter provided several ranges of values with no explanation as to the size of the dataset, the average values for the data points, or enough detail for the EPA to fully evaluate the information. For development of both the proposed and final rule, we have used the best available nationwide data in order to evaluate each of the data points represented in the commenter data. Further, the BSER analysis did not assume that operators would receive a discounted price. However, if you look at the completion cost per day provided in the commenter data, it is not significantly different than the cost per day for a REC as outlined in the TSD.

Regarding the methane content of natural gas, the EPA used the best available nationwide data for calculating the methane and VOC content of natural gas for the oil and natural gas sector as documented in the final rule TSD. In this evaluation for oil wells we found the methane content of raw natural to be 46.73 percent by volume and the VOC content to be 11.62 percent by volume. Based on these composition averages, the cost of control is reasonable. These values are nationwide averages, and there are some basins producing natural gas with lower methane or VOC concentrations that would therefore result in higher cost of control. However, because the rule is based on a nationwide average value, we believe the cost and benefit analysis is representative of nationwide compositions.

Commenter Name: Lee Fuller, Executive Vice President, and V. Bruce Thompson, President
Commenter Affiliation: Independent Petroleum Association of America (IPAA) and the American Exploration and Production Council (AXPC)
Document Control Number: EPA-HQ-OAR-2010-0505-6983
Comment Excerpt Number: 18

Comment: Unlike a natural gas well, where the price of natural gas dictates many operational decisions, the economic driver for oil wells is the price and volume of oil – not natural gas.

When EPA promulgated Subpart OOOO regulations for VOCs and RECs on natural gas wells, EPA indicated it did not have enough information to determine if oil well RECs were cost-effective. The cost-effectiveness of oil well RECs was also raised by EPA in the Methane "White Papers" released on April 15, 2014. IPAA/AXPC and individual member companies submitted comments on EPA's oil well REC White Paper - identifying concerns with the cost-effectiveness of RECs for oil wells. EPA's preamble discussion in Section VII of the proposed standards for oil well RECs makes a general reference to the Technical Support Document (TSD) for the current proposal in terms of justifying its best system of emissions reduction determination, but there is no updated cost/benefit data cited in the proposal. The citations refer back to the "2012 NSPS evaluation." It appears EPA has failed to cite any new or additional information collected since the 2012 evaluation to support the cost-effectiveness of the proposed oil well REC requirements. The economics of natural gas RECs are different and do not support oil well REC requirements.

Response: The EPA disagrees with the commenter that no new data were used in the development of standards for oil well completions. As detailed in the proposal TSD, we obtained 2014 information for well completions from the DrillingInfo database. We then determined which of the wells in the database were hydraulically fractured oil wells, then determined the gas-to-oil ratio (GOR) for each well. Wells with a GOR less than 300 were eliminated from our analysis. For the remaining wells, we determined the average daily gas production, then converted the gas volume to methane and VOC emissions. Therefore, the proposed rule developed new emissions data for oil well completions and we used the same cost as was developed for REC and combustion controls from the 2012 rule, updated from 2008 to 2012 dollars. Therefore, contrary to the commenter's contention, we did not simply rely on the cost effectiveness data that formed the basis of our analysis for the 2012 rule. Please see the TSDs to the proposed and final rules for additional information.

Commenter Name: Kari Cutting
Commenter Affiliation: North Dakota Petroleum Council (NDPC)
Document Control Number: EPA-HQ-OAR-2010-0505-6789
Comment Excerpt Number: 7

Comment: EPA's cost-benefit analysis is deficient because it arbitrarily fails to consider state flaring restrictions in its cost-effectiveness calculation. North Dakota - like most other states - has multiple layers of regulation requiring emissions associated with flowback to be combusted. EPA's rule proposal acknowledges that these state requirements achieve emissions reductions that are comparable to the requirements in the Proposed NSPS OOOOa. But EPA calculates the benefits of the Proposed NSPS OOOOa without taking state requirements into account by assuming that flowback emissions are completely uncontrolled. EPA does so even though it later credits reductions achieved from reduced emission completions ("REC") mandated by other states. EPA's choice to account for only some state control requirements artificially inflates the benefits of the Proposed NSPS OOOOa.

The CAA requires that NSPSs "shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." Accordingly, EPA must choose an NSPS that "represents the best balance of economic, environmental, and energy considerations."

EPA calculated the benefits of the Proposed NSPS OOOOa by assuming that, without the proposal, emissions during flowback would be "vented" to the atmosphere. EPA stated that "[t]he highest emissions are from venting of natural gas to the atmosphere during flowback." This assumption does not account for the fact that the vast majority of such emissions are flared in accordance with state laws, including North Dakota state law. EPA should have reduced the amount of emissions reductions it assumed and credited as a benefit by the amount of control achieved by state-mandated requirements. Indeed, EPA did exactly this by removing from its calculations the value of emissions captured by state-mandated RECs in Colorado and Wyoming. Crediting one form of state-mandated emission control and not another is arbitrary and capricious.

EPA found that both Colorado and Wyoming require RECs for oil and gas wells, so it removed these wells from its cost-benefit analysis. However, EPA made no reference to removing wells for states that require flaring during completion. Instead, EPA calculated the emissions reductions benefits for the Proposed NSPS OOOOa by taking the number of wells that would be subject to the rule (minus the Colorado and Wyoming wells), and multiplying that number by the VOC and methane emissions that would occur "uncontrolled," without accounting for flaring. "The estimates in the table below represent emissions from that population of wells, in the absence of controls. To calculate emissions to the atmosphere using these values, additional information on gas that is not emitted (e.g. through use of RECs or flaring) is needed to reduce the potential value."

EPA found that for a three-day completion event, these "uncontrolled" methane emissions would be 9.72 tons and uncontrolled VOC emissions would be 8.14 tons. EPA multiplied these numbers by the number of wells to determine the total amount of methane and VOC emissions reductions. Then to quantify the methane emissions reductions as a dollar amount, it multiplied the "social cost of carbon" by the total amount of methane emissions reductions. EPA found that based on these emissions reduction benefits, the quantified benefits of the rule justified the costs of compliance.

However, EPA arbitrarily failed to consider that North Dakota and other state regulations require oil well completion emissions to be controlled with flares during the flowback stage. Chapter 33-15-07 of the North Dakota Air Pollution Control Rules states: "No person may cause or permit the emission of organic compounds gases, vapors ... unless these gases and vapors are burned by flares or an equally effective control device as approved by the Department." In addition, the North Dakota Industrial Commission ("NDIC") requires that "[p]ending arrangements for disposition for some useful purpose, all vented casinghead gas shall be burned. Each flare shall be equipped with an automatic ignitor or a continuous burning pilot, unless waived by the director for good reason." Contrary to EPA's assumption, these multiple layers of requirements ensure that it would be illegal in North Dakota to allow emissions during flowback to be "vented" to the atmosphere.

Comparing the North Dakota requirements to the Proposed NSPS OOOOa, there are not flowback emissions that go "uncontrolled" in North Dakota that would otherwise be "controlled" under the Proposed NSPS OOOOa.

EPA acknowledges in the preamble that flaring alone, as is required in North Dakota, achieves the same emissions reductions as the Proposed NSPS OOOOa, finding that "the emissions reduction would be equal." In the Regulatory Impact Analysis ("RIA"), EPA finds that "completion combustion" (i.e., flaring) alone "would achieve direct emission reduction that are equivalent to requiring RECs and combustion, but at an approximately $70 million per year lower cost." If EPA were to consider the emissions reduction benefits that are already being achieved due to flaring requirements in states like North Dakota, the emissions reduction amounts achieved by the Proposed NSPS OOOOa would be much lower, and the overall emission reduction benefits would also be lower.

There is no basis for EPA to consider the REC requirements in Colorado and Wyoming in its cost-benefit analysis but omit flaring requirements in states such as North Dakota. EPA has made an arbitrary calculation of the benefits of the Proposed NSPS OOOOa, which does not meet the standard of "the -best balance of economic, environmental, and energy considerations," as is required under the CAA. The Proposed NSPS OOOOa is therefore contrary to law and should not be finalized as proposed.

Response: For the reasons stated below, the EPA disagrees with the commenter that its cost effectiveness analysis is deficient for not taking into account existing state flaring requirements. Under CAA section 111, the EPA is to evaluate emission reduction systems and set standard of performance that "reflect the degree of emission limitation achievable through the application of the best system of emission reduction." *See* section 111(a)(1). In determining the "best" system, the EPA is required to consider cost, as well as any non-air quality health and environment impacts and energy requirements from the application of such a system. The Administrator must determine that such system "has been adequately demonstrated." An ''adequately demonstrated'' system, according to the D.C. Circuit, is ''one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way.''[1]

The EPA followed the directives in CAA section 111(a)(1)(A) in evaluating the technical capabilities of different control options to reduce VOC and methane from well completions using hydraulic fracturing, including REC, combustion devices, and the combination of REC and combustions. As explained in the EPA's analysis and also noted by the commenter, the EPA

[1] *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 433 (D.C. Cir. 1973), *cert. denied,* 416 U.S. 969 (1974).

concludes that both REC and combustion can achieve 95 percent reduction and are both cost effective. However, REC is a better option because combustion has secondary environmental impact (e.g., NOx emissions).

The EPA does not believe that it is appropriate to take into account existing state requirements in its BSER analysis as this would tend to lock in place existing state requirements even if those controls would not constitute the best system of emission reduction and, as a result, could prevent the EPA from setting standards based on a better technology. Such position would indeed undermine and frustrate the Congressional mandate to set the standards of performance based on the best system of emission reduction as discussed above. It is also inaccurate and unworkable for setting national standards because not all states have requirements or the same requirements.

We further note that North Dakota issued an order on July 1, 2014, to reduce the flared volume of gas, reduce the number of wells flaring, and reduce the duration of flaring from wells.[2] North Dakota has also set a state goal to increase gas capture. In light of the above, we do not believe that North Dakota would prefer flaring over REC where REC is technically feasible, which is what the NSPS requires.

Lastly, it appears that the commenter may be conflating the cost evaluation in the BSER analysis, which is governed by the CAA, with the regulatory impact analysis required for economically significant rules by Executive Order 13563 and Executive Order 12866. These are two independent and separate analyses with different requirements. Please see the RIA for a more detailed discussion.

With respect to the comment as it relates to the RIA, the EPA agrees with the commenter that the cost-benefit analysis in the proposed RIA did not appropriately characterize the contribution of current North Dakota regulations to the emissions and costs evaluation. As a result, for the final rule we have taken into account that North Dakota requires flaring into our baseline analysis in the RIA. That is, for wells that were previously flaring, as required by North Dakota, we only accounted for the additional cost of imposing REC requirements, but did not account for any methane or VOC emission reductions, because we assume this is comparable to flaring. More specifically, for these wells, we only took into account the costs of our rule, with no incremental benefits. For Subcategory 2 wells where only combustion is required, we assumed there would be no change from the baseline North Dakota requirements, so no costs or benefits were assumed. We believe that this representation of well in North Dakota is more appropriate based on the level of control required by the existing regulations.

Commenter Name: Michael Turner, Senior Vice President, Onshore
Commenter Affiliation: Hess Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6960
Comment Excerpt Number: 6

[2] See DCN EPA-HQ-OAR-2010-0505-6960, Excerpt 6.

Comment: In the Proposed OOOOa Rule, EPA arbitrarily fails to consider that North Dakota and other state regulations require crude oil well completion emissions to be controlled with flares during the flowback stage. Chapter 33-15-07 of the North Dakota Air Pollution Control Rules states, "No person may cause or permit the emission of organic compounds gases, vapors ... unless these gases and vapors are burned by flares or an equally effective control device as approved by the Department." In addition, the NDIC requires that "[p]ending arrangements for disposition for some useful purpose, all vented casinghead gas shall be burned. Each flare shall be equipped with an automatic ignitor or a continuous burning pilot, unless waived by the director for good reason." Contrary to EPA's assumption, these multiple layers of requirements ensure that it would be illegal in North Dakota to allow emissions during flowback to be "vented" to the atmosphere.

In North Dakota, there are no flowback emissions that are "uncontrolled" that would otherwise be "controlled" under the Proposed OOOOa Rule. The Proposed OOOOa Rule requires: 1) during the initial flow back stage, routing flowback into tanks and commencing operation of a separator unless technically infeasible; 2) during the separation phase, routing liquids into tanks or collection system, or reinjecting the liquids into the well; 3) during the separation phase, routing gas into a gas flow line or collection system, reinjecting the gas into the well, or using the gas as an on-site fuel source or other useful purpose, unless infeasible; 4) during the separation phase, routing of all salable quality gas to the gas flow line as soon as practicable, unless technically infeasible; and 5) capturing and directing gas that is not able to be directed to a flow line to a "completion combustion device." A "completion combustion device" is defined as "any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions." A "completion combustion device" includes a flare.

EPA acknowledges in the preamble that flaring, which is required in North Dakota, achieves the same emissions reductions as the Proposed OOOOa Rule, finding that "the emissions reduction would be equal." In the RIA, EPA finds that "completion combustion" (i.e., flaring) alone "would achieve direct emission reduction that are equivalent to requiring RECs and combustion, but at an approximately $70 million per year lower cost." If EPA were to consider the emissions reduction benefits that are already being achieved due to flaring requirements in states like North Dakota, the emissions reduction amounts would be much lower, and the overall emission reduction benefits would also be lower.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6789, Excerpt 7.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 66

Comment: RECs, where feasible, are considered standard industry practice. The proposed rule recognizes this fact in the proposed OOOOa rulemaking and in its technical white paper on the subject. See 80 Fed. Reg. at 56,632 (Noting that "[s]everal public and peer reviewer comments on the white paper noted that these technologies are currently in regular use by industry to control oil well completion and recompletion.") Given RECs are already standard industry practice, this proposed rule only serves to remove operational flexibility and add significant recordkeeping and recording burden without any additional environmental benefit. As such, the Alliance believes this provision of the proposed rule is unnecessary.

Response: We disagree with the commenter that the requirements of the rule are unnecessary because they are considered to be "standard" practice or are being voluntarily implemented. Further, the establishment of the standard can provide more equity for operators who have voluntarily chosen to control emissions consistent with best practice.

With respect to requirements for recordkeeping with respect to the rule, we believe that the required records are consistent with those that are maintained in practice by the owners and operators during the completion with very little additional information. The documentation supporting a claim of technical infeasibility is likely the only additional recordkeeping that is required beyond what would normally be recorded by an operator during a completion. As the commenter notes, REC is a standard industry practice, and we envision that analyses would be conducted before a decision is made to deviate from the standard practice. The additional recordkeeping in this final rule is simply documentation of such analysis for enforceability and therefore would not create much additional burden.

Commenter Name: C. William Giraud
Commenter Affiliation: Concho Resources Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6847
Comment Excerpt Number: 9

Comment: Currently, for oil well completions Concho already uses Reduced Emissions Completions (RECs) when it is possible to place gas into a pipeline. Our practice is to operate a separator as soon as possible after flowback begins when there is sufficient gas available. This is a standard industry practice and has been recognized as such by the EPA. Concho is already voluntarily reducing emissions by using RECs where practical, therefore this proposed portion of the rule is unnecessary. If adopted, the provision would stifle operational flexibility and burden operators with significant recordkeeping without additional reductions in emissions.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6930, Excerpt 66.

Commenter Name: Wesley D. Lloyd, Freeman Mills PC
Commenter Affiliation: Texas Independent Producers and Royalty Owners Association (TIPRO)
Document Control Number: EPA-HQ-OAR-2010-0505-6893
Comment Excerpt Number: 17

Comment: As IPAA/AXPC notes in its comments, EPA incorrectly assumes that reduced emission completions on oil wells are the same as reduced emission completions on natural gas wells. Unlike natural gas wells, some oil wells lack clear initial and separation flowback stages. Oil well reduced emission completions (REC) should consider the availability of a gathering line to determine the feasibility of an oil well completion.

Further, implementing REC or combustion devices/flares at oil wells is redundant and unnecessary because operators already engage in such practices at a majority of wells. EPA should avoid implementing a blanket, national per well standard on methane and VOC emissions due to variations between well types and wells in different regions. Wells producing both oil and gas further support the need to avoid a national, blanket emissions standard because many of these wells already utilize REC or combustion devices.

Response: Please see responses to DCN EPA-HQ-OAR-2010-0505-6930, Excerpt 66 and DCN EPA-HQ-OAR-2010-0505-6787, Excerpt 32.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 34

Comment: Proposed Standards for Hydraulically Fractured Exploratory and Delineation Wells (Subcategory 2 Wells)

We recommend that the EPA also give consideration to emissions that occur during the period when the wells are initially placed online. (Please see image below) Regulations need to adequately protect public health for those living and attending school measureable feet from well sites.

Response: In the final rule, Subcategory 2 wells are required either to route all flowback directly to a completion combustion device or, at the owner or operator's option, route the flowback to a well completion vessel and route the separated gas to a completion combustion device as soon as a separator is able to operate. Under both options, combustion is not required in situations that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. We believe these requirements address the commenter's concerns.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)

Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 31

Comment: Proposed Standards for Hydraulically Fractured Exploratory and Delineation Wells (Subcategory 2 Wells)

Further, we recommend that all unconventional shale hydraulically fractured wells must utilize REC equipment.

Response: As detailed in the TSD for the final rule, BSER for Subcategory 2 wells was determined to be combustion of flowback gases. RECs were not considered to be BSER for Subcategory 2 wells primarily because of the lack of natural gas gathering lines at these wells.

Commenter Name: Cory Pomeroy, General Counsel
Commenter Affiliation: Texas Oil & Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-7058
Comment Excerpt Number: 83

Comment: EPA should not prescribe a particular technological system that must be used to comply with a standard of performance for REC. Rather, EPA should set the standard of performance for REC, consistent with Section 111(a)(1) of the Act, and owners and operators should have the flexibility to meet that standard using any means that are feasible. Furthermore, EPA should not prescribe arbitrary criteria or thresholds defining feasibility. Owners and operators should be allowed to select any measure or combination of measures that will achieve the emissions level of the standard.

Proposed Section 60.5375a(a)(1)(ii) requires that a REC be conducted, except if it is "technically infeasible" to route the recovered gas from the separator into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an on-site fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve.

We are concerned that the term "technically feasible" could be broadly interpreted in practice after the rule is issued. Feasibility of meeting REC provisions of Section 60.5375a(a)(1)(ii), most importantly the feasibility of capturing and routing the recovered gas from a hydraulically fractured well to a gathering system pipeline, includes economic and many other considerations in addition to "technical" considerations.

Establishing a bright line for overall feasibility of conducting REC for oil wells is not practical. Owners and operators should have the option, based on technical, economic and other factors, to use a completion combustion device to reduce methane and VOC emissions from hydraulically fractured oil well completions.

EPA should revise the term "technically feasible" in proposed Section 60.5375a(a)(1) to simply "feasible" and EPA should not set threshold criteria for "feasibility" but rather should leave that to case-by-case assessment.

Response: As shown in our BSER analysis for subcategory 1 wells, REC is better than combustion (lack of secondary impacts such as NOx emissions) but cannot be implemented in some instances due to technical limitations, in which event combustion is required except in limited circumstances specified in the rule.

The final rule does not define "technical infeasibility" due to the difficulty of providing a clear definition that could encompass all such situations. Instead, we have expanded recordkeeping requirements in the final rule to include: (1) the reasons for the claim of technical infeasibility with respect to all four options provided in §60.5375a(a)(1)(ii), including but not limited to, name and location of the nearest gathering line; capture, re-injection, and reuse technologies considered; aspects of gas or equipment prohibiting use of recovered gas as a fuel onsite; and (2) technical considerations prohibiting any other beneficial use of recovered gas on site.

We believe these additional provisions will support a more diligent and transparent application of the intent of the technical infeasibility exemption in the final rule. We also believe these changes should alleviate concerns the commenter may have had that the technical infeasibility option is too narrowly construed.

3.3 Estimated Number of Wells

Commenter Name: Richard A. Hyde, P.E., Executive Director
Commenter Affiliation: Texas Commission of Environmental Quality (TCEQ)
Document Control Number: EPA-HQ-OAR-2010-0505-6753
Comment Excerpt Number: 18

Comment: The TCEQ believes that the EPA has substantially underestimated both the number of potentially affected sources and the cost of compliance with the regulations. The proposed regulations refer to 20,000 active well sites. In the state of Texas alone, there are over 100,000 gas and 190,000 oil wells currently producing, with at least 10,000 new wells drilled annually, plus thousands of existing wells that are re-worked or recompleted.

Response: In our analysis we used data from the DrillingInfo database that indicated whether a well was completed within each year. The data indicated that 13,696 hydraulically fractured oil wells were completed or recompleted in Texas for the base year 2012. This number is consistent with the number the commenter cites for new wells drilled annually in Texas. The 20,000 active well number cited by the commenter is the total number of hydraulically fractured oil wells completed or recompleted nationwide in 2012. Note that Texas activity numbers contributes a significant portion of the national total.

3.4 Estimated Emissions per Completion

Commenter Name: Douglas E. Jones, Chairman
Commenter Affiliation: Pennsylvania Grade Crude Oil Coalition (PGCC)
Document Control Number: EPA-HQ-OAR-2010-0505-6239
Comment Excerpt Number: 8

Comment: PGCC would also note that the white papers produced by the EPA reference a lot of information and data collected from gas wells and unconventional well sites but contain almost no actual information from conventional oil well sites. PGCC submits this lack of data results in flawed or skewed perceptions as to the actual emissions from those types of sites.

Response: The EPA believes that a conventional well site, as that term is used by the commenter, is a vertically drilled well without hydraulic fracturing. We point out that the affected facility for well completions in the final rule is defined as "a single well that conducts a well completion operation following hydraulic fracturing or refracturing." Thus, a conventional well is not an affected facility under the well completion provisions of the final rule, and data specific to conventional wells are not germane to the analyses conducted in the development of the final rule.

Commenter Name: Lee Fuller, Executive Vice President, and V. Bruce Thompson, President
Commenter Affiliation: Independent Petroleum Association of America (IPAA) and the American Exploration and Production Council (AXPC)
Document Control Number: EPA-HQ-OAR-2010-0505-6983
Comment Excerpt Number: 18

Comment: Finally, IPAA/AXPC continues to believe EPA's cost-effectiveness analysis for oil well completions is flawed because it is taking "credit" for well completions industry has already done or will do regardless of regulations. IPAA and WEA filed extensive comments on EPA's oil well completion White Paper on June 16, 2014. The issues raised in that process have not been adequately addressed by EPA in the RIA or Technical Support Document for this rulemaking. The most relevant provisions of those comments are reproduced below:

"Finally, we question the need or benefit of EPA requiring reduced RECs or combustions devices/flares at oil wells as operators are already engaged in such practices at a majority of the wells. There is a clear economic incentive to capture as much of the gas as possible and where it is not possible to capture the gas, safety concerns for the personnel at the well site drive the installation of flares. It is a matter of economics and common sense—if the gas can be captured economically, it will be. If it cannot be captured economically, and it is present in sufficient quantities to represent a safety concern, it is flared. See the comments above, as they pertain to EPA's data sources and estimates. For the reasons set forth above, we have considerable doubt as to the accuracy of the national and per well estimates of methane and volatile organic compounds ("VOC") emissions for hydraulically fractured oil well completions. There is significant variation in the emissions among different well types and wells from different regions. As such, a "national estimate" will not necessarily be representative of wells from a particular region (and, in fact, would be representative only by chance).

As to factors that influence emissions, there are numerous factors that were not discussed in the White Papers. Most importantly, the White Papers do not adequately address the complex nature of what EPA terms "co-produced" wells, where both oil and gas are produced. Such wells are difficult to classify in terms of how any given well will behave in a wide variety of geologic formations and basins. In addition, EPA does not discuss the well-established fact that nearly all oil wells that produce appreciable amounts of gas are controlled by a combustion device for safety reasons. As mentioned above, the existing economic and safety incentives result in a majority of these wells being "controlled"—whether by a REC or combustion device. In fact, a survey submitted as part of the docket for NSPS Subpart OOOO was conducted by AXPC/ANGA member companies that showed that greater than 90% of wells were controlled prior to the rulemaking. Comment submitted by Amy Farrell, Vice President of Regulatory Affairs, America's Natural Gas Alliance (ANGA) and Bruce Thompson, President, American Exploration and Petroleum Council (AXPC); EPA-HQ-OAR-2010-0505-4241. A similar Texas Energy Alliance survey had comparable results, again supporting the position that further EPA requirements mandating REC/flares are not necessary."

In the TSD for the proposed Subpart OOOOa, EPA continues to claim ignorance as to the extent state and local regulations require well completions and claim an arbitrarily low assumption that only 7 percent of completions are controlled in the absence of federal regulations. This arbitrarily low assumption skews EPA's cost-effectiveness and takes "credit" for activities the industry is doing on its own.

Response: The EPA believe our estimate that 7 percent of well completions are covered by state regulations is accurate. In the TSD to the preamble, we clearly presented the steps of our analysis to arrive at the 7 percent value; therefore, the 7 percent value is not arbitrary as suggested by the commenter. We note that the commenter provided no data to dispute that estimate. For the final rule, we added all new wells in North Dakota to the total numbers of wells regulated at the state level.

Concerning the effects of voluntary measures, we recognize that some owners and operators have recently implemented voluntary measures to reduce emissions throughout the oil and natural gas production sector, and we applaud their efforts. However, contrary to the commenter's contention, these voluntary efforts do not skew the cost effectiveness determinations that form the basis of the final rule. The cost effectiveness determinations are focused on the cost and emission reductions for a single source to implement a control option. This determination would be the same regardless of how many sources are actually implementing the control options.

3.5 Types of Oil Wells not Capable of Performing a REC

Commenter Name: Douglas E. Jones, Chairman
Commenter Affiliation: Pennsylvania Grade Crude Oil Coalition (PGCC)
Document Control Number: EPA-HQ-OAR-2010-0505-6239
Comment Excerpt Number: 3

Comment: Reduced emissions completions on conventional gas wells would yield minimal results. The completions are done quickly and the opportunities for gas recovery are few. The costs would outweigh the benefits many fold. In addition, after stimulation cleanup takes hours, not days. The extra cost is not justifiable and the additional equipment needs would likely cause delays in the process, further adding costs.

In addition, conventional oil wells are almost always placed on production immediately after completion. There is no period of frac water cleanup. The wells is pumped and frac water is recovered along with oil and gas in surface production equipment immediately after stimulation. No gas is vented while the well cleans up.

Overall the PGCC would further comment that reduced emissions completions or combustion are not really options for shallow conventional oil well completions. Shallow oil well completions in Pennsylvania are nearly always performed on under pressured reservoirs using water as the completions fluid. Very few chemicals are utilized in shallow conventional oil well completions. As a result the reservoir is overbalanced during the completions and gives up only minor amounts of natural gas. The cost of the technology for either reduced emissions completions or combustions would kill the industry and gain nearly no benefit to the environment.

In addition, nearly all shallow conventional oil wells drilled by PGCC membership are commingled with other wells into a common tank battery. Often as many as 30 to 50 wells into a single tank battery. It would be nearly impossible for the producer to establish numbers for single wells. Gas from these wells is produced in a like manner. They are almost never metered on an individual basis.

E or heat content and how is the producer to know how to calculate that number.

The PGCC supports an exemption from reduced emissions completions or the use of combustion equipment during stimulation for stripper wells, low pressure wells and conventional wells if the questions noted above can be answer.

Response: First, regarding conventional wells, we point out that the affected facility for well completions in the final rule is defined as “a single well that conducts a well completion operation following hydraulic fracturing or refracturing.” Thus, a conventional well is not an affected facility under the well completion provisions of the final rule, and data specific to conventional wells are not germane to the analyses conducted in the development of the final rule. Further, we recognize that for some wells, completions are of short duration or go immediately to production. Our BSER analysis considered an average completion duration of 3 days, with some completions will be longer and some shorter, however, we have no data or supporting information that a short duration completion precludes the ability to conduct a REC. Where the well can meet the low pressure well definition, the final rule provides that the well does not have REC requirements, but instead has to route to a completion combustion device. As for materials that are routed to storage vessel, if the gas is not separated then it does not need to be tracked (or metered). Additionally, any gas that is part of the initial flowback it is not regulated under the rule.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 60

Comment: Issue – EPA needs to accommodate additional exemptions for certain oil well completions. There are a wide range of conditions experienced across different oil and natural gas fields and additional provisions are needed in the rule to clearly exempt certain scenarios.

Recommendation – In addition to the exemption for wells producing less than 300 scf of gas per bbl of oil, EPA should include exemptions for wells requiring artificial lift to complete flowback and for periods when flowback has stable entrained gas, foam, emulsion, or infrequent slugging gas flow such that a separator cannot be operated.

Wells Requiring Artificial Lift In Order To Flow Back The Completions Fluids Should Be Exempt From The Well Completion Affected Facility.

EPA should exempt hydraulically fractured oil wells that require artificial lift in order to flow back the completions fluid. Many oil reservoirs have pressure that is insufficient for wells to naturally flow even after hydraulic fracturing. This can be evidenced by the prevalence of artificial lift equipment such as rod pumps visible across the landscape of many oil producing areas. In order to operate a two or three phase gas/liquid separator there must be both sufficient wellhead pressure and a sufficient quantity of gas in the flowback fluid. Lack of insufficient gas volumes results in the inability to operate a separator during flowback, which makes both a REC and combustion of emissions technically infeasible. The regulation should not require operators to set up a separator on-site and attempt to utilize the separator when it is known that it will never be operated. This results in extraneous costs for minimal emission reductions since there is insufficient gas available to operate the separator.

Examples of this are reservoirs in the Permian Basin where horizontal drilling is used to extend the life of existing producing formations. Many oil wells that are hydraulically fractured do not have sufficient reservoir pressure to flowback and there is insufficient gas to flare. One API Company estimates that approximately 30% of its hydraulically fractured horizontal wells and 80% of its hydraulically fractured vertical wells in the Permian Basin require artificial lift to flowback. Instead, following a hydraulic fracture, rod pumps are installed on the wells to artificially lift the fracture fluids either to fracture tanks or storage vessels. Other examples include reservoirs in the north central East Texas basin which produce heavy black oil, also called "dead oil" because there is no associated gas produced with the oil. In this area, gas to operate separation must be purchased as it is not available from well production.

API recommends the suggested revision to the definition of well affected facility:

§60.5365a(a) Each well affected facility, which is a single well that conducts a well completion operation following hydraulic fracturing or refracturing and has a gas-to-oil ratio of greater than 300 scf of gas per <u>stock tank</u> barrel of oil produced. <u>Wells that must use artificial lift equipment to flowback completion fluid are not well affected facilities</u>.

API also recommends the addition of the following definition for Artificial Lift Equipment in §60.5430a:

<u>*Artificial Lift Equipment* means the use of mechanical pumps (e.g., rod pumps or electric submersible pumps) to flowback fluids from a well</u>.

Response: See section VI.E.4 of the preamble to the final rule for discussion of this issue.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 58

Comment: Exemptions From REC Requirements For Certain Hydraulically Fractured Oil Wells

22.2.1 EPA Is Correct When It States In The Preamble (FR 56633) That "Oil Wells Cannot Perform A REC If There Is Not Sufficient Well Pressure Or Gas Content During The Well Completion To Operate The Surface Equipment Required For A REC."

In order to operate a two or three phase gas/liquid separator there must be both sufficient wellhead pressure and a sufficient quantity of gas in the flowback fluid. Lack of insufficient gas volumes results in the inability to operate a separator during flowback, which makes both a REC and combustion of emissions technically infeasible. The regulation should not require operators to set up a separator on-site and attempt to utilize the separator when it is known that it will never be operated. This results in extraneous costs for no tangible emission reduction since there is insufficient gas to operate the separator. Therefore, there are several instances where EPA should provide exemptions for the proposed REC requirements. Some of these exemptions may overlap since all involve the technical infeasibility of operating a gas/liquid separator in order to conduct a REC.

Response: See the response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 60.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 69

Comment: The oil and natural gas industry is constantly looking for ways to maximize efficiency and product recovery—including in the completions process. However, the rule must recognize the numerous instances where RECs may be infeasible for technical reasons or for circumstances beyond an operator's control. For instance, low pressure oil wells may produce associated gas; but the pressure differentials between a gas gathering system and the well may require substantial compression in order to move gas from the wellhead separator into the gathering system. In some instances, overcoming this pressure differential may be too costly and impractical from an economic standpoint. And the emissions from the required compression might actually negate any environmental benefit associated with gas capture.

Response: The EPA agrees with the commenter and have finalized the rule to include an exemption for low pressure wells from the REC requirements which we believe will address the scenarios presented by the commenter. Low pressure wells have completion combustion requirements.

Commenter Name: Kari Cutting
Commenter Affiliation: North Dakota Petroleum Council (NDPC)
Document Control Number: EPA-HQ-OAR-2010-0505-6789
Comment Excerpt Number: 11

Comment: Furthermore, many of the wells in the Bakken are oil wells that do not have sufficient well pressure or gas content during the well completion to tie into gathering lines.

Due to these varied factors, the NDPC respectfully requests that EPA deem the use of REC "technically infeasible" where production is not tied to a gathering line under the following situations:
• low pressure or low gas content;
• midstream delays that are beyond the operator's control;
• longer negotiation periods due to lack of eminent domain;
• line/capacity issues (as a result of continued expansion of development);
• force majeure; or
• where curtailment would be unreasonable due to reservoir damage and oil royalty discontinuation for gas capture reasons.

Establishing a bright line for overall feasibility of conducting REC for oil wells is not practical due to the varied scenarios that may occur. Owners and operators should have the flexibility, based on technical, economic and other factors, to use a completion combustion device to reduce methane and VOC emissions from hydraulically fractured oil well completions under the scenarios described above.

Response: We agree that the circumstances under which a REC is technically infeasible are varied and, therefore, it is difficult to provide one definition that can address all scenarios. For that reason, the final rule instead requires that an owner or operator document the circumstances and rationales for invoking the "technical infeasibility" exemption for a given well completion. We believe that this requirement provides sufficient flexibility to address site specific factors.

While we are not defining in the final rule "technical infeasibility" for purposes of exempting REC, We do, however, want to clarify that the exemption is necessarily limited to "technical" infeasibility, which can include safety and engineering concerns, as well as unexpected and unplanned process malfunctions or force majeure. Even so, the use of a technical infeasibility exemption is applied on a site specific basis, and none of these examples are universally determinative.

We note that the commenter provides examples of "infeasibility" within the context of the ability to tie into a gathering line. Routing of emissions recovered to a gathering line is only one of the options included in the definition for REC in the final rule which must be explored before determining that REC is technically infeasible. The options are to 1) route to a gas flow line or collection system, 2) re-inject into a well or another well, 3) use as on-site fuel, or 4) use for another useful purpose that purchased fuel or raw material would serve. This definition is the same as the definition for REC in subpart OOOO which, in response to public comment, included options in addition to routing to a gas flow line.[3] Under the final rule, an owner and operator is exempt from REC if it documents the circumstances and issues supporting technical infeasibility for all of these options, not just for routing to a gas flow line.

With respect to the examples the commenter provided, we believe we have sufficiently addressed the use of REC for low pressure wells and low gas to oil ratio with the final rule requirements. Midstream delays that are beyond the operator's control would impact the ability to route to a gathering line, but would not necessarily impact re-injection or beneficial use under one of the other options. Negotiations for imminent domain may or may not be a valid claim for technical infeasibility depending on the site specific facts, including the owner's due diligence in commencing such negotiations in a timely fashion such that it was not simply the lack of proper planning. Regarding line/capacity issues, we would hope that gas gathering infrastructure will continue to improve over time, such that, this becomes less of a reason for technical infeasibility. We are not certain the commenter's use of the term "force majeure" but as that term has been used in the NSPS program for performance test delays to generally mean acts of nature, acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility, those could be considered to provide for technical infeasibility analysis. Regarding curtailment which would damage a well, we are not sure of the scenario where REC would result in such curtailment, but to the extent curtailment does present a safety hazard or damage to a well, this could be provided in the technical infeasibility analysis. Finally, loss of royalty is an economic issue, not a technical one. We have already accounted for cost in establishing BSER.

Any owner or operator claiming technical infeasibility has the burden to demonstrate the claim based on the relevant information. In any subsequent review of a technical infeasibility, EPA will

[3] For example, see page 35 of the 2012 RTC document: Docket ID EP-HQ-OAR-2010-0505-4546.

independently assess the basis for the claim to ensure flaring is limited and emissions are minimized, in compliance with the rule.

Commenter Name: Kari Cutting
Commenter Affiliation: North Dakota Petroleum Council (NDPC)
Document Control Number: EPA-HQ-OAR-2010-0505-6789
Comment Excerpt Number: 12

Comment: If EPA finalizes the Proposed NSPS OOOOa, it should at a minimum acknowledge that the state of North Dakota has already made a determination of technical infeasibility under the July 2014 Flaring Order with respect to the ability for operators to tie into a gathering line. As described above, the NDIC issued its Order after finding that:

Total gas plant capacity in North Dakota exceeds total gas production in the state although many bottlenecks exist in the current gas gathering infrastructure due to the high liquid content of the gas, the prolific volumes of oil and gas during initial production, increasing pipeline pressure that requires installation of additional compressors, and in some cases undersized pipe. Most operators are prudently attempting to connect their wells to a gas gathering system, but due to many aforementioned constraints in the gas gathering systems, much of the gas is not processed.

EPA should clarify that the state's finding in the July 2014 Flaring Order is sufficient to establish "technical infeasibility" under Proposed Section 60.5375a(a)(l)(i)-(ii).

Response: To the extent that the commenter is claiming that the North Dakota July 2014 Flaring Order establishes that RECs are not technically feasible in that state, we disagree. While the issues described in the comment could likely make it technically infeasible to route the recovered gas to a gathering line during a given well completion, there is no evidence that these issues occur in every well completion in North Dakota. Today's final rule requires that an owner or operator document the circumstances and rationales for invoking the "technical infeasibility" exemption for a given well completion. We believe that this requirement provides sufficient flexibility to address specific factors affecting a given well completion.

We also want to emphasize that REC, as defined in this final rule, includes all of the following options: 1) route to a gas flow line or collection system, 2) re-inject into the well or another well, 3) use as on-site fuel, or 4) use for another useful purpose that purchased fuel or raw material would serve. This definition is the same as the definition for REC in subpart OOOO which, in response to public comment, included options in addition to routing to a gas flow line.[4] The circumstances described in the comment appear to relate solely to the technical feasibility of routing recovered gas to a gas flow line. As with routing to a gas flow line, we realize that there may be various factors that would render the other options technically infeasible (e.g., unavailability of a well for reinjection, unavailability of equipment that can utilize the gas, or a

[4] For example, see page 35 of the 2012 RTC document: Docket ID EP-HQ-OAR-2010-0505-4546.

safety reason associated with re-injection[5]). Under the final rule, an owner and operator is exempt from REC if it documents the circumstances and issues supporting technical infeasibility for all of these options, not just for routing to a gas flow line.

Commenter Name: C. William Giraud
Commenter Affiliation: Concho Resources Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6847
Comment Excerpt Number: 10

Comment: There are certain situations where using RECs are impractical and flaring is the only alternative. Concho cannot capture and must flare in areas where pipelines are either unavailable or already at capacity, venting as little gas as possible. In addition, when a gas plant shuts down either for maintenance or unforeseen circumstances, an operator's only option is to flare because capturing and sending the gas through a pipeline is no longer a viable option. Furthermore, flares are common to industry and, for safety reasons, venting rarely occurs. Seeking to minimize venting through this proposed rule is unnecessary given industry practice.

Response: We agree with the commenter that there are situations such as gas plant shut downs where combustion is the only alternative. Therefore, we have finalized the rule to include the exemption to REC requirements for reasons of technical infeasibility. As such, combustion is allowed provided the operator has demonstrated that it was technically infeasible to capture and use the gas for any useful purpose. The final rule requires that the owner/operator keep records that document the analysis of REC technical infeasibility.

Regarding the comment that the rule is unnecessary, see response to DCN EPA-HQ-OAR-2010-0505-6930, Excerpt 66.

Commenter Name: John Robitaille
Commenter Affiliation: Petroleum Association of Wyoming (PAW)
Document Control Number: EPA-HQ-OAR-2010-0505-6854
Comment Excerpt Number: 16

Comment: Oil Well Completions: EPA should give owners and operators the option to use a completion combustion device based on specified technical, economic, and other delineated factors. EPA should deem the use of a combustion device unavoidable in specified situations where production is not tied to a gathering line, midstream delays are beyond the operator's control, and other unique circumstances discussed in further detail below.

[5] Id.

For non-wildcat, non-delineation wells, EPA proposes that for hydraulically fractured oil well completions, owners and/or operators use reduced emissions completions, also known as "RECs" or "green completions," to reduce methane and VOC emissions and maximize natural gas recovery. See 80 Fed. Reg. at 56,595. To achieve these reductions, EPA proposes operators use RECs in combination with a completion combustion device. See id. Importantly, EPA indicates that it does not intend to require RECs where their use is "technically infeasible." See id. EPA requests comments on specific criteria regarding infeasibility, particularly regarding the availability of gathering lines, as well as any other factors that could be specified in the NSPS for requiring recovery of gas from well completions. See 80 Fed. Reg. at 56,634.

PAW respectfully comments that EPA should deem the use of a combustion device allowed due to infeasibility in situations including, but not limited to: the unavailability of gas gathering lines; low pressure or low gas content wells; midstream delays beyond the operator's control such as extended right-of-way negotiation periods due to lack of eminent domain; gathering line pressure and capacity issues (as a result of continued expansion of development); force majeure; and where curtailment of production would be unreasonable due to potential reservoir damage, and oil royalty payment discontinuation due to inability to capture gas. Establishing a bright line for overall feasibility of conducting REC for oil wells is not practical. Owners and operators should have the option, based on technical, economic and other factors, to use a completion combustion device to reduce methane and VOC emissions from hydraulically fractured oil well completions. Situations like these frequently arise in Wyoming making a reduced emission completion infeasible.

PAW suggests that while REC is already required by WDEQ when possible, there has to be equipment in place along with compatible well and line pressures to ensure success. Three things are required to complete a well with the REC process: (1) Gas-gathering infrastructure (REC cannot be performed without pipelines); (2) the gas must be capable of flowing at pressure equal to or greater than the gas pipeline system; and (3) the gas must be of adequate quality to meet the pipeline specification (no CO_2 or N_2 present).

When a gas well is hydraulically fractured, its primary flowback fluid is natural gas. For this reason, RECs make sense to reduce the amount of natural gas vented or flared into the atmosphere. For oil wells, however, the primary fluid is oil. In some cases, little to no gas is produced and may not be observed during the flowback process. In other cases, oil wells can be very prolific and a substantial amount of gas can be seen during the flowback process. No "one size fits all" standard is appropriate for oil wells.

Location of pipelines relative to the well is critical to the viability of REGs. A "sales line " must be near enough to be economically feasible to connect prior to the completion of the well. In typical high-density infill projects, the infrastructure and certainty of production make this technique feasible. This fact will most likely preclude a step out or wildcat as typically no lines will be available. Companies will not lay pipeline to a well unless it is determined the well is productive. It is worthy of note that not all open - hole logs give a definitive answer as to the productivity of the well.

To flow a well to a sales line during flowback, following frac stimulation, the reservoir needs to be of a quality and pressure that it will flow back with a full column of water, and have enough wellhead pressure to get into the sales line with the gas. An over-pressurized interval with good deliverability will usually flow at a high enough pressure to flow back to sales. Overly tight, normally pressured, naturally under pressured or partially depleted reservoirs will not flow back against line pressure at a rate necessary to clean the gel from the frac stimulation. This is also true if the reservoir is depleted or of poor quality in general. If the gas contains impurities (such as sand, free water, too much water vapor, or significant amounts of carbon dioxide or nitrogen) it cannot be placed in a sales line. Typical equipment used during REGs are capable of separating out the condensate, water and solids out of the production stream; however the equipment does not remove carbon dioxide or nitrogen. The use of carbon dioxide and nitrogen is commonly added to a frac on a partially depleted or under- pressurized zone to assist with flowback and reduce the chances for reservoir damage. Due to the addition of these gases, in partially depleted or under-pressurized zones, the flowback gas cannot be deemed pipeline quality.

In certain instances drillable plugs are utilized to isolate intervals between fracs during the stimulation process. After all fracs are complete, the plugs are drilled out, either with a coiled tubing unit, a snubbing unit or a combination of service rig and snubbing unit. Drill out procedures is done with the well in an under-balance condition so as not to damage the zones that were just stimulated. Nitrogen or air is commonly used to create a foam for these drill outs and clean outs. During this procedure the well has to flow up the casing to remove plug cuttings, frac fluid and water. The rate and pressure of the returns on the casing is constantly changing, which makes meeting the marketable gas requirements extremely difficult. Typically in multiple zone areas, the lower zones will show higher pressures than in upper zones. These pressure differences can be magnified by the presence of partially depleted intervals. Where high differential pressures exist between intervals, it becomes difficult, if not impossible to clean the wells enough to go to a sales line. The additional backpressure required to flow to sales can cause a situation where the high-pressured zones flow to the low pressure zones instead of up the casing. This situation can cause additional problems with pipe becoming stuck at perforations or the need to add nitrogen, which eliminates saleable gas. Retrievable bridge plugs are also utilized for isolation of intervals. A common way to retrieve these bridge plugs is circulating nitrogen or foam to clean them and snub out of the hole. This usually precludes the ability to sell gas during these operations.

In high-pressure instances, due to minimizing flaring and the restrictions on flowback equipment and pipelines, pressures can buckle tubing. This instance could result in a hazardous well control situation. A common way to reduce pressure is to send some gas to flare. Either differential sticking or buckled tubing can result in an expensive "fishing job" to retrieve stuck or broken tubing or possibly the complete loss of the well. Each well should be evaluated prior to drill out to determine the operational viability of drilling out to sales. Wells without significant depletion, wells of average productivity, combined with low pipeline pressures are preferred for the REC technique.

Cold temperature can complicate operations on high-pressure gas wells due to hydrate formation freezing off flow lines. The additional piping and equipment that is necessary for REGs can aggravate this situation. Flowing back to a sales line usually precludes the possibilities of getting flowing pressures below the hydrate point. Equipment and setup must be designed to take this phenomenon into consideration. Control of pressure drops, liberal applications of heat, and generous additions of methanol are all requirements for successful cold weather REGs. Under extreme cold weather conditions, flow back to flare is usually more prudent as hookups are generally less complicated and less prone to freeze up.

Only wells with sufficient reservoir pressure to flow against the gathering system back pressure and capable of producing saleable quantities of natural gas are candidates for REGs. Without a gas gathering system, combustion is still the next best option to control gas emissions during flowback.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6789, Excerpt 11.

With respect to the examples identified in the comment, we want to clarify that the technical infeasibility exemption for REC does not apply to the economic issues mentioned by the commenter.

Also, we believe that the use of inert gases or anti-freezes, which render the gas unusable in the sales line may be evaluated for technical infeasibility for that option. The use of such inert gases or anti-freezes may or may not have an impact on the use of the recovered gas under one of the other beneficial use options, but in the site specific situations where it does render the gas unusable for any beneficial use, the owner or operator may put forth that analysis in their claim of technical infeasibility.

Commenter Name: Joshua M. Kindred
Commenter Affiliation: Alaska Oil & Gas Association (AOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6879
Comment Excerpt Number: 9

Comment: Verify Technically Infeasible Exemptions. The EPA concludes that "oil wells cannot perform a Reduced Emission Completion (REC) if there is not sufficient well pressure or gas content during the well completion to operate the surface equipment required for a REC." In order to operate a two or three phase gas/liquid separator there must be both sufficient wellhead pressure and a sufficient quantity of gas in the flowback fluid. Lack of sufficient gas volumes results in the inability to operate a separator during flowback, which makes both a REC and combustion of emissions technically infeasible. To state this another way, if it is technically infeasible to use a separator, it is also technically infeasible to flare, because you cannot flare all the produced fluids. The regulation should not require operators to set up a separator on-site and attempt to utilize the separator when it is known that it will never be operated. This results in extraneous costs for no tangible emission reduction since there is insufficient gas to operate the separator. Therefore, there are several instances where EPA should provide exemptions for the proposed REC requirements.

AOGA believes that the EPA's proposed regulations are flawed given an apparent assumption that reduced emission completions on oil wells are substantially similar to reduced emission completions on natural gas wells. This flaw is problematic for a number of reasons. First, it likely illustrates failings relating to any cost-benefit analysis the EPA might have undertaken. Intuitively, the price of natural gas dictates operational decisions on natural gas wells, while the price and volume of oil is the economic driver for oil wells. It is not clear to AOGA whether the EPA considered accurate and appropriate information regarding its evaluation supporting the cost-effectiveness of the proposed oil well reduced emission completion requirements. It is inarguable that the economics related to natural gas reduced emission completions are substantially different and fail to constitute sufficient support for mandating the proposed oil well reduced emission completion requirements.

Second, the more significant distinction relates to how the fundamental process of reduced emission completions differ, despite the EPA's assumption to the contrary. Although there may be occasional instances of oil wells possessing relatively clear initial and separation flowback, it is possible that oil wells will lack a separation flowback stage given the lack of gas or quality of gas such that operation of a separator is not feasible. Quite simply, the EPA's proposed regulations fail to account for the complexity of the flowback process for oil wells. Generally speaking, flowback is routed to a separator almost immediately in order to route the gas to a secure location. Minimizing back-pressure on the well to ensure both maximum flow and cleanup is essential. Perhaps more so than with reduced emission completions on natural gas wells, the various stages of flowback on oil wells is difficult to clearly delineate and, as a result, a separator's optimal utilization is truly a function of engineering judgment. In practice, well-head pressure fluctuates greatly and unpredictably.

However, AOGA hopes that the EPA appreciates these issues and have provided the necessary flexibility with the inclusion of the "technically infeasible" exemption. As the EPA notes, "[t]here may be cases in which, for reason(s) not within an operator's control, the well is completed and flowback occurs without a suitable flow line available." The EPA appears to equate the lack of a gas flow line suitable for new production with technical infeasibility, and AOGA would encourage the EPA to be more emphatic with outlining this exemption so that it has the breadth and certainty to cover North Slope oil operations.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 60.

With respect to the specific comment on the EPA's analysis of the costs of the control options considered for well completions, section 111 requires that we consider costs in evaluating control options. In evaluating control costs, the EPA adhered to the guidance from the D.C. Circuit in a string of case law, which provided various formulations of the cost standard-" exorbitant," "greater than the industry could bear and survive," "excessive," and "unreasonable." *See* 80 FR 56593, 56616. We find the analysis to look into the economics, which we understand to be whether control is economical, inconsistent with the cost standard established by the case law.

Additionally, we believe that the cost of control analysis conducted for oil well completions is representative for oil wells. The emissions calculated were based on estimated oil well gas production data. The only factors that were the same as gas wells in the analysis was the cost for conducting a REC and the value of any recovered gas.

3.5 Low GOR Wells

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 31

Comment: EPA proposes to exclude low production wells (equivalent to 15 barrels of oil per day and low gas-to-oil ratio of less the 300 scf/bbl) from the "green completions" requirements as well as fugitive emissions standards applicable to well sites. Kinder Morgan supports this approach. Many oil wells in older producing fields that are being redeveloped with new technology often produce very little if any gas during well completion. These wells can be identified before the well completion stage by demonstrating the known lease gas and oil production rates from existing wells located on or near the same lease (and then verified after completion).

Response: We are not finalizing the proposed exclusion of wells with low GOR from the definition of a well affected facility. The EPA proposed that wells with a GOR of less than 300 scf of gas per barrel of oil produced would not be affected facilities subject to the well completion provisions of the NSPS. The reason for the proposed threshold GOR of 300 was that separators typically do not operate at a GOR less than 300, which is based on industry experience rather than a vetted technical specification for separator performance. Though in theory any amount of free gas could be separated from the liquid, in reality this is not practical given the design and operating parameters of separation units operating in the field. However, in the final rule low GOR wells still have no well completion requirements. In order to ensure that low GOR claims are not being made without sufficient analysis and oversight, the final rule requires that records used to make the GOR determination must be retained and a certifying official must sign the low GOR determination. Please see section VI.E.3 of the preamble to the final rule for further discussion of this topic.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 59

Comment Excerpt: API Agrees With A Minimum GOR Of 300 Scf/Bbl As An Exemption Threshold In The Definition Of A Well Affected Facility Per § 60.5365a(A) But Recommends Language Be Amended For Consistency With The Greenhouse Gas Reporting Program.

API supports EPA's conclusion that hydraulically fractured oil wells with a gas-to-oil ratio (GOR) of less than 300 scf/bbl of oil produced should not be affected facilities subject to the well completion provisions of Subpart OOOOa. EPA's reasoning on FR 56633 for exempting low GOR oil wells is accurate. Operators in a given basin or field that are drilling and completing wells from specific formations generally have good knowledge and understanding of whether REC separator equipment can technically be operated on similar wells. There is also sufficient data on well GORs drilled in the same area and in the same formations. API further recommends EPA amend the exemption language to be consistent with the Greenhouse Gas Reporting Program in such that the definition of the gas well affected facility in §60.5365a(a) be amended to the following:

Each well affected facility, which is a single well that conducts a well completion operation following hydraulic fracturing or refracturing and has a gas-to-oil ratio of greater than 300 scf of gas per stock tank barrel of oil produced. The provisions of this paragraph do not affect the affected facility status of well.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 31.

Commenter Name: Lindel Fowler, Acting Executive Director
Commenter Affiliation: Railroad Commission of Texas
Document Control Number: EPA-HQ-OAR-2010-0505-6917
Comment Excerpt Number: 5

Comment: The Commission joins TCEQ in supporting proposed exemptions for low production well sites of less than 15 barrels of oil equivalent or less per day (BOEPD) and sites with less than 300 SCF/bbl gas-to-oil ratio. The Commission also urges EPA to establish other exemptions for small oil and gas sites based on reasonably limited emissions or equipment.

Response: Concerning the 15 boe low production well exclusion, we did not receive sufficient data to show that low production wells have lower emissions during completion than other hydraulically fractured wells. In addition, we did not receive comment on ways these wells could be identified prior to well completion. Therefore, low production wells will remain affected facilities in the final well completion requirements.

Concerning the proposed exclusion of wells with low GOR from the definition of a well affected facility, please see the response for DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 31.

Commenter Name: Alvyn A. Schopp, Chief Administration Officer and Regional Vice President and Treasurer
Commenter Affiliation: Antero Resources Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6935
Comment Excerpt Number: 7

Comment: USEPA is proposing that wells with a gas-to-oil ratio (GOR) of less than 300 scf of gas per barrel of oil produced would not be affected facilities subject to the well completion provisions of the NSPS. USEPA solicits comment on whether a GOR of 300 is the appropriate applicability threshold. Antero supports the exclusion of wells with GOR less than 300 scf per barrel of oil from the definition of an affected facility for well completion purposes. Wells with a GOR of less than 300 scf are not significant emission sources and regulatory efforts and limited resources should focus on more significant emission sources. The regulation of such smaller sources would result in a diversion of resources, both from the agency and the regulated community, to address small sources of emissions whose control would result in little if any benefit to the environment and public health while resulting in a significant cost to the industry.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 31.

Commenter Name: Cory Pomeroy, General Counsel
Commenter Affiliation: Texas Oil & Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-7058
Comment Excerpt Number: 60

Comment: EPA is proposing that wells with a "gas-to-oil ratio (GOR) of less than 300 scf of gas per barrel of oil produced would not be affected facilities subject to the well completion provisions of the NSPS." EPA solicits comment on whether a GOR of 300 is the appropriate applicability threshold, and if the GOR of nearby wells would be a reliable indicator in determining the GOR of a new or modified well. The reason for the proposed threshold GOR of 300 is that separators typically do not operate at a GOR less than 300, which is based on industry experience rather than a vetted technical specification for separator performance. Though, in theory, any amount of free gas could be separated from the liquid, the reality is that this is not practical given the design and operating parameters of separation units operating in the field. Specifically, EPA states,

> We believe that having no threshold may create a significant burden for operators to control emissions for these wells with just a trace of gas. EIA data show that the number of 'oil only' wells drilled from 2007–2012 was less than 20 percent. The potential emission characteristic of oils with a GOR of 300 is relevant when deciding whether this is a reasonable threshold.

EPA notes that on February 24, 2015, API submitted a comment to EPA stating that oil wells with GOR values less than 300 do not have sufficient gas to operate a separator.

TXOGA supports the GOR threshold and recommends that EPA provide a definition of GOR in Section 60.5430a to mean the volume of natural gas produced at the surface at standard conditions, standard cubic feet (scf), divided by the volume of hydrocarbon liquids produced at the surface at stock tank conditions, stock tank U.S. petroleum barrel, bbl. This definition would be consistent with, and further clarify, the definition set out in 40 C.F.R. part 63 Subpart HH—NESHAP from Oil and Natural Gas Production Facilities, Section 63.761. The proposed definition is also widely understood in the industry and consistent with a series of articles published by William D. McCain *et al.*, which are cited extensively by EPA in its rulemaking pertaining to Subpart HH.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 31.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 66

Comment: EPA requests comment on an exemption for wells with average daily production less than 15 bbl oil equivalents (BOE) per day. Under this exemption, a marginally higher percentage of wells and emissions would be subject to the REC requirements than under the GOR exemption. If wells were exempted for either the GOR or production thresholds, a slightly lower percentage of wells and emissions would be subject to the REC requirements.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6917, Excerpt 5.

Commenter Name: Mike Gibbons, Vice President – Production
Commenter Affiliation: CountryMark Energy Resources, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-6241
Comment Excerpt Number: 40

Comment: We have reviewed the proposed exemptions that are recommended by EPA. We believe that the exemptions may be reasonable for large wells that are operated in major basins such as the Bakken, Eagle Ford, or Permian Basin; but are not technically possible in a mature basin such as the Illinois Basin.

The average well produced in the Illinois Basin has an Initial Production (IP) of less than 35 barrels per day (BPD). If a new well meets EPA's threshold of 300 SCF/bbl, the gas production from a 35 bpd well would be 10.5 MSCFD. We do not believe that separators will properly operate with a flow rate that is this low. Wells that are producing 500 bpd of oil in the Bakken, Eagle Ford, or Permian Basins would have a gas flow rate of 150 MSCFD (assuming 300 SCF/bb;), which would be a suitable volume to reliably operate a separator. We recommend a minimum gas flow rate of 25 MSCFD be established for operators with low-flow wells.

Low gas rates will require us to provide supplemental gas flow (i.e. propane) to the emissions reduction system to sustain 95% combustion and maintain pilot operation. Adding propane increases CO2 emissions and our operating costs. This constraint is not beneficial for EPA to meet emissions reduction targets nor for the operator to maintain cost effective operations.

As discussed above, the low gas flow rates (10.5 MSCFD) is not a large enough volume for us to install a gas collection and processing facility. With the cost to construct a relatively small gas processing facility possibly costing $2.5 million, we would need to produce 3.6 billion SCF for the project to financially break even (assuming a constant price at $2.40/MCF).

In addition to low gas flow rates, we also experience slug flow from oil wells after the well is completed. Slug flow is defined by, “a liquid–gas two-phase flow in which the gas phase exists as large bubbles separated by liquid "slugs". The inconsistent flow of gas and liquid to the separator and combustion device will result in owners/operators being unable to safely and reliably operate the equipment.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6917, Excerpt 5.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 65

Comment: EPA has proposed that wells with gas-to-oil ratios (GOR) less than 300 scf per bbl would not be subject to REC requirements. As the rationale for setting this threshold, EPA states that “we set a of GOR of less than 300 scf/barrel as the threshold under which an oil well completion would not be reasonably capable of capturing and controlling emissions” due to the fact that such a well “will not likely have enough gas associated that it can be separated.” However, the proposed rule already exempts wells from the REC requirements if a separator cannot function. As such, the proposed GOR exemption is duplicative and not necessary.

The <300 scf per bbl GOR threshold is reasonable for decreasing the number of subject wells with minimum impact on the coverage of total emissions, but it results in the exemption of about 2% of wells with emissions exceeding 1 ton of methane. These exempt, relatively high emission wells are primarily those with very high oil production and >100 scf per bbl GOR.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 31.

Commenter Name: Steven A. Buffone
Commenter Affiliation: CONSOL Energy Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6859
Comment Excerpt Number: 7

Comment: CONSOL supports an applicability threshold for the completion provisions for oil wells based on the gas to-oil-ratio (GOR) of the well. However, we believe the proposed GOR of 300 scf of gas per barrel of oil produced is not an appropriate threshold for determining the applicability of the completion provisions for oil wells. CONSOL recommends that the applicability threshold for the proposed completion provisions for oil wells be set at or near the upper end of the referenced "black oil" GOR value of 900. "Black oils" are not likely to not have gases or light hydrocarbons associated with it and therefore would have minimal fugitive emissions.

CONSOL would also suggest that EPA allow the submittal of regional GOR data as representative of individual well sites that are new or modified.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 31.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 67

Comment Excerpt: Nevertheless, if EPA decides to retain this exemption, we propose an alternate formulation, as described below. To determine the effect of this exemption, we analyzed data from the production database DI Desktop for approximately 20,000 oil wells (i.e., production type "oil" or "O&G") that were completed in 2014. For individual wells, potential completion flowback methane emissions were assumed to equal three days of practical initial gas production (2nd month of reported production) with 78.8% methane content. Table 9 summarizes the number of wells, average potential emissions, and total potential emissions of wells subject to or exempt from REC requirements under different exemptions. If wells with GOR less than 300 scf per bbl are exempt, 70% of wells and 99.61% of emissions would still be subject to the REC requirements, notwithstanding other exemptions.

An alternative exemption based on gas production is more effective for reducing emissions because potential emissions are more directly related to gas production, but depend on the interaction of GOR and oil production. For example, an exemption for wells with less than 10 Mcf gas per day would result in 58% of wells and 99.91% of emissions being subject to the REC requirements. We recommend that EPA consider exempting wells that produce less than 10 Mcf gas per day instead of those with less than 300 scf per bbl GOR or 15 BOE per day. Operators likely can predict the initial gas production of a well more accurately than GOR, which further increases the value of basing the exemption on gas production. EPA Greenhouse Gas Reporting data includes 28 records of hydraulically fractured gas well completions with measured flowback rates below 10 Mcf per day that recovered gas to sales; this supports the feasibility of RECs for wells with production equal or greater than 10 Mcf per day.

[Table 9: Percent of Oil Wells and Completions Emissions subject to REC requirements Under different exemptions]

Response: See response to DCN EPA-HQ-OAR-2010-0505-6917, Excerpt 5.

Commenter Name: Kevin J. Moody, General Counsel
Commenter Affiliation: Pennsylvania Independent Oil & Gas Association (PIOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6943
Comment Excerpt Number: 10

Comment: PIOGA believes that the GOR of nearby wells is a reliable indicator of GOR for a new or modified well.

Based on the actual experience of member companies, PIOGA believes the GOR of nearby wells is a reliable indicator of the expected GOR for a new or modified well from the same reservoir. .

Response: See the response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 31.

3.6. Low Production Wells

Commenter Name: Mike Cantrell, Chairman
Commenter Affiliation: National Stripper Well Association (NSWA)
Document Control Number: EPA-HQ-OAR-2010-0505-6758
Comment Excerpt Number: 10

Comment: In the rulemaking EPA attempts to define low production well sites as having an "average combined oil and natural gas production for the wells at the site being less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production." While it would appear that this provision is designed to be helpful for small independent operators, NSWA raises concerns with the provision as it applies to wells later in life. Today's high-volume horizontal wells are tomorrow's stripper wells. As noted, wells decline in production over their lifespan, and while a well may have originally started with higher production rates of both oil and natural gas, while it nears the end of its life cycle, a well will likely produce only a fraction of that. Considering that this rule will affect wells making modifications, basing the exemption on what the well "averaged over the first 30 days of production" is an ineffective measurement. A clearer exemption would be for low production wells regardless of original production. As mentioned previously, and recognized by EPA, small producers are likely to produce minimal emissions, if any, and the wasteful duplicative requirements being required by EPA in this rulemaking would constitute an overwhelming financial burden on small producers.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6943, Excerpt 5.

Commenter Name: Kevin J. Moody, General Counsel
Commenter Affiliation: Pennsylvania Independent Oil & Gas Association (PIOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6943
Comment Excerpt Number: 7

Comment: However, the metric for establishing the 15 boe/day values in the referenced definition is on a calendar year basis, not on the first 30 days of operation as EPA proposes. Basing the exemption threshold criteria on average combined oil and gas production over only the first 30 days of production would not be representative for many low production (i.e., stripper) wells in Pennsylvania. For example, at a typical oil well in Southwestern Pennsylvania, initial production could peak between 20 and 50 boe/day within the first few weeks or first month of production following completion, but then drop very quickly to less than the proposed 15 boe threshold. PIOGA suggests that the 15 boe threshold be based on the average production over the first 90 days of production for stripper wells. Given the ability of operators within a given region to accurately predict well performance as discussed below, a 90 day evaluation period would provide a more representative characterization of the long-term productivity of a given well.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6943, Excerpt 5.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 32

Comment: EPA proposes to exclude low production wells (equivalent to 15 barrels of oil per day and low gas-to-oil ratio of less the 300 scf/bbl) from the "green completions" requirements as well as fugitive emissions standards applicable to well sites. Kinder Morgan supports this approach. Many oil wells in older producing fields that are being redeveloped with new technology often produce very little if any gas during well completion. These wells can be identified before the well completion stage by demonstrating the known lease gas and oil production rates from existing wells located on or near the same lease (and then verified after completion).

Response: See response to DCN EPA-HQ-OAR-2010-0505-6943, Excerpt 5.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 75

Comment: EPA proposes to exclude low production wells (equivalent to 15 barrels of oil per day and low gas-to-oil ratio of less the 300 scf/bbl) from the "green completions" requirements as well as fugitive emissions standards applicable to well sites. Kinder Morgan supports this approach. Many oil wells in older producing fields that are being redeveloped with new technology often produce very little if any gas during well completion. These wells can be identified before the well completion stage by demonstrating the known lease gas and oil production rates from existing wells located on or near the same lease (and then verified after completion).

Response: See response to DCN EPA-HQ-OAR-2010-0505-6943, Excerpt 5.

Commenter Name: Steven A. Buffone
Commenter Affiliation: CONSOL Energy Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6859
Comment Excerpt Number: 9

Comment: EPA is requesting comment on excluding low production wells (i.e., those with an average daily production of 15 barrels of oil equivalent [BOE] or less) from the standards for well completions.

- CONSOL generally agrees that low production wells should be excluded from the proposed standards and that the proposed low production well site threshold of 15 BOE equivalent based on the definition of a stripper well property in IRC 613A(c)(6)(E) is reasonable. However, basing the threshold criteria on the first 30 days of production would not be representative. Initial production could peak and then drop (by as much as 75% or more) very quickly. CONSOL suggests that the 15 BOE threshold be evaluated after the first 90 days of production. That period would provide a more representative characterization of the long-term productivity of a given well

Response: See response to DCN EPA-HQ-OAR-2010-0505-6943, Excerpt 5.

Commenter Name: Lee Fuller, Executive Vice President, and V. Bruce Thompson, President
Commenter Affiliation: Independent Petroleum Association of America (IPAA) and the American Exploration and Production Council (AXPC)
Document Control Number: EPA-HQ-OAR-2010-0505-6983
Comment Excerpt Number: 18

Comment: IPAA/AXPC supports the various exclusions from the oil well REC requirements for oil wells less than 15 boe; wells with a gas-to-oil ratio (GOR) of 300 or less; and the low-pressure well. Although not an exact science, operators can make engineering judgments and estimations based on experience in a developed formation. If the well initially exceeds 15 boe, a potential solution is to allow the operator to temporarily shut in the well and bring in REC equipment or limit the production such that the well does not make more than 15 boe for any measurement period as long as the average rate of the averaging period is 15 boe or less. In the event that the operator, based on strong well performance, decides to bring in REC equipment, he could earn a 0 bopd credit to the averaging period for every day the REC is used.

Response: See response to DC EPA-HQ-OAR-2010-0505-6943, Excerpt 5.

Commenter Name: Douglas E. Jones, Chairman
Commenter Affiliation: Pennsylvania Grade Crude Oil Coalition (PGCC)
Document Control Number: EPA-HQ-OAR-2010-0505-6239
Comment Excerpt Number: 4

Comment: Conventional oil wells in Pennsylvania are nearly always stripper wells from the first days of production, however some may not qualify as stripper wells until a month or two of production has taken place. Nearly all are stripper wells based on daily average first year production. The EPA definition of stripper wells should be based on the nationally recognized standard based on yearly average production.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6943, Excerpt 5.

Commenter Name: J. Jared Snyder
Commenter Affiliation: New York State Department of Environmental Conservation.
Document Control Number: EPA-HQ-OAR-2010-0505-6894
Comment Excerpt Number: 10

Comment: EPA requested comment on whether an oil well producing less than 15 barrels per day equivalent may be defined as a low producing well. The DEC agrees with this definition of a low producing well.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6943, Excerpt 5.

Commenter Name: Kevin J. Moody, General Counsel
Commenter Affiliation: Pennsylvania Independent Oil & Gas Association (PIOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6943
Comment Excerpt Number: 5

Comment: PIOGA generally supports the exclusion of "low production well sites" from the completion requirements of proposed Subpart OOOOa.

Nearly all PIOGA operators are small business entities. Many of the wells that they develop are "conventional" or vertical wells that typically meet the "low production site" criteria as proposed in Subpart OOOOa. As stated in the proposed regulations, "low production wells have inherently low emissions". PIOGA believes that the proposed low production well site threshold of 15 barrels of oil equivalent (boe) based on the definition of a stripper well property in IRC 613A(c)(6)(E) is reasonable.

Response: We did not receive sufficient data to show that low production wells have lower emissions during completion than other hydraulically fractured wells. In addition, we did not receive comment on ways these wells could be identified prior to well completion. Therefore, low production wells will remain affected facilities in the final well completion requirements.

Commenter Name: J. Jared Snyder, Assistant Commissioner for Air Resources, Climate Change Energy
Commenter Affiliation: New York State Department of Environmental Conservation (DEC)
Document Control Number: EPA-HQ-OAR-2010-0505-7006
Comment Excerpt Number: 13

Comment: EPA requested comment on whether an oil well producing less than 15 barrels per day equivalent may be defined as a low producing well. The DEC agrees with this definition of a low producing well.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6943, Excerpt 5.

Commenter Name: Kevin J. Moody, General Counsel
Commenter Affiliation: Pennsylvania Independent Oil & Gas Association (PIOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6943
Comment Excerpt Number: 9

Comment: EPA solicited comment regarding the ability of owner/operators and regulators to identify low production wells prior to completion. As explained in PIOGA's comments to EPA as a small entity representative (SER) to the Small Business Advocacy Review Panel (SBARP), in many instances a producer can accurately predict "stripper" well status with confidence. Many smaller operators drill in areas where the geological/producing formations have been proven (developed in the past), and as a consequence drillers are able to accurately predict how these wells will perform going forward. In such instances, the vast majority will meet the definition of "stripper wells". For the purpose of these comments "stripper well" includes the categories of wells that are commonly referred to as "conventional wells", "low pressure wells", "low volume wells", and "vertical wells" among others. As stated, the physical, technical, economic, and operational characteristics of stripper wells are vastly different from hydraulically fractured horizontal wells.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6943, Excerpt 5.

Commenter Name: Kevin J. Moody, General Counsel
Commenter Affiliation: Pennsylvania Independent Oil & Gas Association (PIOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6943
Comment Excerpt Number: 3

Comment: PIOGA suggests that well completions lasting less than 24 hours be expressly excluded from the completion requirements of proposed Subpart OOOOa.

In response to EPA's request for comment, PIOGA suggests that an alternative exclusion from the completion requirements for oil wells be added to address completions that occur over a short duration (i.e., hours versus days) and usually without a discernable flowback. PIOGA suggests that well completions lasting less than 24 hours be expressly excluded from the completion requirements of proposed Subpart OOOOa because of the small volume of methane and VOC emissions that occur over the short duration of flowback.

The duration of flowback where the flow is gas or oil dominant is very short (a few hours), making it nearly impossible for a producer to recoup the cost of an REC through gas sales. U.S. EPA asserted that since "wells" are flowed back for 3 to 10 days after treatment, the operator could recoup the cost of reduced emission completion (REC) equipment by directing the flowback gas through a sales meter. This scenario may be true for high volume, unconventional horizontal wells, but this is not the case for stripper wells. In addition, to properly remove fracturing fluid from the well bore and stimulated reservoirs of an unconventional well after treatment, much more time is required, perhaps twice as much as for a conventional well, thereby impacting cost and schedule.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6859, Excerpt 8.

3.7 Low Pressure Well Definition

Commenter Name: Steven A. Buffone
Commenter Affiliation: CONSOL Energy Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6859
Comment Excerpt Number: 6

Comment: The term "low pressure gas well" as proposed in Subpart OOOOa is not appropriate for defining hydraulically fractured wells. CONSOL believes that the Independent Petroleum Association of America's (IPAA) comment letter to EPA, dated April 22, 2015, regarding the definition of "low pressure gas well" provides a workable definition for the technological feasibility of REC for both hydraulically fractured gas and oil wells. We would request that the EPA please refer back to these IPAA comments cited above and incorporate them into the proposed definition.

Response: We agree that the proposed definition of "low pressure well" did not appropriately characterize hydraulically fractured oil wells or more generally petroleum wells for which conducting an REC would be technologically infeasible. To address all petroleum wells rather than just gas wells, we have revised the equation in the definition for "low pressure well" in the final rule to add pressure drop resulting from flow of oil and water in a well. Please see section VI.E.4 of the preamble to the final rule for a detailed discussion of the revised equation.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 57

Comment: The Proposed Definition In §60.5430a For Low Pressure Well Is Inconsistent With The Amended Definition Of Low Pressure Well In 80 FR 48268, August 12, 2015 §60.5430.

EPA's proposed definition for low pressure well in §60.5430a is the following:

"Low pressure well means a well with reservoir pressure and vertical well depth such that 0.445 times the reservoir pressure (in psia) minus 0.038 times the vertical well depth (in feet) minus 67.578 psia is less than the flow line pressure at the sales meter."

API supports the following amendment to this definition that was finalized by EPA in §60.5430 (80 FR 48268) on August 12, 2015 as the following:

Low pressure well means a well with reservoir pressure and vertical well depth such that 0.445 times the reservoir pressure (in psia) minus 0.038 times the <u>true</u> vertical well depth (in feet) minus 67.578 psia is less than the flow line pressure at the sales meter.

Response: We appreciate the commenter's thorough review and have made conducted a thorough analysis of the low pressure equation to address both oil and gas wells and have made the appropriate corrections in the final rule. See §60.5432a.

Commenter Name: Cory Pomeroy, General Counsel
Commenter Affiliation: Texas Oil & Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-7058
Comment Excerpt Number: 62

Comment: EPA should provide a new definition of "low pressure oil well" to differentiate oil wells versus gas wells. The definition of "low pressure well" set out in proposed Section 60.5430a and taken from the definition of "low pressure gas well" in Subpart OOOO (Section 60.5430) is not appropriate for a low pressure oil well. In the current subpart OOOO, the term low pressure gas well means a well with reservoir pressure and vertical well depth such that 0.445 times the reservoir pressure (in psia) minus 0.038 times the true vertical well depth (in feet) minus 67.578 psia is less than the flow line pressure at the sales meter.

Low pressure oil wells may not produce enough gas to merit sales; hence there would not be a gas gathering system available for a REC nor sufficient gas to operate a separator. In addition, TXOGA requests that EPA include an exemption for wells on mechanical artificial lift. While the universe of wells that would need this exemption may be narrow, we request that EPA develop an exemption that addresses the mechanical artificial lift issue, since there are situations where BSER is not a combustion device because of the level of flow.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6859, Excerpt 6.

Commenter Name: Lee Fuller, Executive Vice President, and V. Bruce Thompson, President
Commenter Affiliation: Independent Petroleum Association of America (IPAA) and the American Exploration and Production Council (AXPC)
Document Control Number: EPA-HQ-OAR-2010-0505-6983
Comment Excerpt Number: 18

Comment: IPAA supports the inclusion of an exclusion for a "low-pressure oil well" but it is not appropriate to utilize the definition for a "low-pressure gas well." Oil and water are fairly equivalent on their impact on the intent of this low-well pressure exemption in the early phases of flowback, and the water/oil ratio will change significantly during the early flowback periods for hydraulically fractured wells. The main difference is that, once the hydraulic fracture load stops coming back, a gas well will typically have much less liquids in the production tubing, making the surface pressure actually higher for the gas well vs. an oil well. This difference would be reflected in the 0.038 number which represents the gas gradient in the well, which would impart a back pressure. For oil wells this back pressure would be higher, i.e. more liquids in the tubing, and this factor should be increased. For example a well making 15 boe up 2-3/8" production tubing at a 300 GOR could have a gradient of 5 to 10 times as much. The new record-keeping requirements associated with oil RECs (but also applicable to natural gas RECs) disproportionately impact the smaller, independent operators (conventional operations).

Response: See response to DCN EPA-HQ-OAR-2010-0505-6859, Excerpt 6.

3.8 Separators

Commenter Name: Cory Pomeroy, General Counsel
Commenter Affiliation: Texas Oil & Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-7058
Comment Excerpt Number: 59

Comment: TXOGA notes that in some instances, when fracturing a well at an existing site, an operator may proceed directly from the initial flowback phase to the production phase, without having a separation stage. Under these circumstances, there is no separator flowback phase. TXOGA interprets the proposed regulatory provisions to make these recordkeeping requirements inapplicable. Simply put, there would be no process for which to create a record. It would be helpful for EPA to confirm this interpretation in the preamble to the final rule, such that owners and operators need only comply with the requirements applicable to each stage of the process that in fact occurs. Here, the only requirements applicable to the initial flowback phase and production phase apply.

Response: We believe the commenter's reference to recordkeeping requirements is in reference to §60.5420(c) with respect to tracking gas captured, duration and other information related to the completion. Those records would only apply to the separation flowback stage of the completion since initial flowback is not regulated under the rule. If there is no separation flowback stage, as indicated by the commenter, then the record would state zero for the duration of the flowback stage.

Commenter Name: Jack Dalrymple, Chairman, Governor, Wayne Stenehjem, Attorney General and Doug Goehring, Agriculture Commissioner
Commenter Affiliation: North Dakota Industrial Commission (NDIC)
Document Control Number: EPA-HQ-OAR-2010-0505-6977
Comment Excerpt Number: 2

Comment: Operational standard verses NDIC defined numeric standard: North Dakota regulations for gas capture clearly define the initial flowback stage of well completions as 14 days. The proposed rule defines the flowback stage as the time when it is "technically infeasible" for a separator to function. In addition, North Dakota regulations for gas capture clearly define the separator flowback stage for a well completion as 90 days. The proposed rule defines this stage as the time when it is "technically infeasible" to route the recovered gas into a gas flow line or collection system, re-inject the recovered gas, use the recovered gas as an on-site fuel source, or use the recovered gas for another useful purpose. The proposed rule does not define "technically infeasible." This results in a clear conflict between the proposed rule which contains undefined operational standards and existing North Dakota rules which contain a clearly defined numerical standard.

Response: The definitions of the stages of flowback in the rule are solely for the purposes of the NSPS regulation. Likewise, the definitions of these stages in any state or other regulation are not applicable to NSPS requirements.

Commenter Name: Mike Gibbons, Vice President – Production
Commenter Affiliation: CountryMark Energy Resources, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-6241
Comment Excerpt Number: 59

Comment: Our experience in the Illinois Basin is that most of our wells do not naturally flow under reservoir pressure. Completion rigs are often required to swab the wells to promote liquid and gas flow from the well. This results in intermittent flow from the well, which results in unsteady state operation of the separator and combustion device. Our experience is that a separator will not work for every well completion, as EPA has proposed.

As discussed above, our experience drilling and producing wells in the Illinois Basin is that the oil production and gas flow rates are lower than what EPA has considered when developing the regulation. Most of the wells that we produce exceed EPA's proposed exemption levels, but result in unstable operation of the emissions reduction equipment.

Response: The EPA appreciates the information provided by the commenter. We agree that REC may not work in some instances, therefore, we have finalized with an exemption to REC requirements for reasons of technical infeasibility. If an operator claims a technical infeasibility exemption to a REC, §60.5420(c) provides additional recordkeeping requirements.

Commenter Name: Steven A. Buffone
Commenter Affiliation: CONSOL Energy Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6859
Comment Excerpt Number: 8

Comment: CONSOL also recommends inclusion of an exemption for oil wells where completions occur over a short period of time (less than 24 hours). In such cases where completions occur over a period of hours verses a period of days. These oil wells have very short flowback periods rendering the use of separators technologically infeasible. Because of the short completion times and minimal amount of related methane and VOC emissions, CONSOL requests that these oil wells be exempted from the proposed Subpart OOOOa requirements.

Response: The EPA does not agree that an exemption from REC requirements due to duration of the completion is warranted. We have based our BSER analysis on the average duration of an oil well completion, and as would be expected, there will be some completions will be of lower duration than the average and we don't believe that a short duration completion precludes being able to conduct a REC.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 62

Comment: EPA Should Clarify That A Separator Is Not Required To Be Onsite During The Initial Flowback Stage When It Is Technically Infeasible To Operate.

Certain wells produce flowback with stable entrained gas, foam, emulsion, or infrequent slugging gas flow. Gas from hydraulically fractured oil well flowback often initially starts appearing in slugs before the flow begins to stabilize. Infrequent slugs of gas may drive liquids and/or foams into the gas lines unless a prohibitively large gas space above the liquid/foam is maintained in the separator (see section 12.1). These conditions do not supply a sufficiently steady stream of gas to operate a separator such that flowback from these wells never leave the initial flowback stage prior to production In these situations, it is unclear if operators are required to rent separation equipment to have onsite even knowing the equipment would never be utilized due to well characteristics and engineering constraint. API believes it was EPA's intent to not require separation equipment to be onsite during the initial flowback stage based on the definitions proposed in §60.5430a and the requirements in §60.5375a(a)(1)(i) and §60.5375a(a)(1)(ii). This would result in extraneous compliance costs for minimal emission reduction since there is insufficient gas to operate the separation equipment. Therefore, API requests EPA clarify that well completion operations that remain in the initial flowback stage through the start of production are not required to have a separator onsite or exempt wells where field experience indicates that flowback fluid characteristics demonstrate that a sufficient and steady amount of gas is not available to operate a separator. In instances where flowback fluid deviates from expected offset well performance such that separation of gas is practical, the operator should stop flowback (in initial flowback stage) and restart the well completion operation in separation flowback stage after separation equipment is installed.

API recommends the following clarification be added to §60.5375a(a)(1)(i):

(i) During the initial flowback stage, route the flowback into one or more well completion vessels or storage vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the initial flowback stage is not subject to control under this section. <u>A separator is not required to be located onsite during the initial flowback stage. Once conditions allow for separation, then the operate must immediately stop the well completion operation, install a separator, and restart the well completion operation in the separation flowback stage.</u>

Response: We agree with the commenter that the rule was not clear on whether REC equipment was required to be present during the initial flowback stage. We disagree however, that this equipment does not need to be present. The final rule requires that gas be captured as soon as the separator is able to be used, therefore, if the separator is not present, the operator would not be able to demonstrate compliance with this requirement. Further, demonstration of attempts to run the separator would not be possible without the equipment present. Therefore, the final rule has been revised to require that REC equipment be present onsite during the entire completion event. See also section VI.E.1 of the preamble to the final rule.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 63

Comment: As the proposed rule is written, some operators may be unable to comply with the oil well completion requirements. For example, in fields with small volumes of associated gas like the Permian Basin, operators may be unable to run a three-phase separator. Fields that produce heavier crudes—like in Utah's Uinta Basin—face similar logistical challenges running a three-phase separator.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6241, Excerpt 59.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 75

Comment: We recommend the final rule defers to operator knowledge to determine when green completions are feasible. Operator expertise and field knowledge will be sufficient to determine whether there is enough gas to operate a temporary separator.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6854, Excerpt 16.

Commenter Name: Kevin J. Moody, General Counsel
Commenter Affiliation: Pennsylvania Independent Oil & Gas Association (PIOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6943
Comment Excerpt Number: 4

Comment: As stated, oil well completions in Southwestern Pennsylvania typically occur over a period of several hours (versus days). Because of the typically short duration of flowback and lack of a separation flowback stage, separators are generally not used during oil well completions. While the use of separators during such completions may be technically feasible in some cases, their use is not economically feasible. Typically, once stripper oil wells stop returning fracturing fluids and transition to a gas dominant or oil dominant flow, the flowback procedure ends and the wells are shut-in. There is no separation flowback stage. The flowback process consists of an initial flowback stage and a production stage only. Much of the time, the flowback stage is less than 24 hours.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6859, Excerpt 8.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 68

Comment: In section VIII.F.3. of the preamble to the proposed rules, EPA states that, "Recent information indicates that some wells, because of certain characteristics of the reservoir, do not need to employ a separator." In this context, EPA is soliciting comments on, "(1) the role of the separator in well completions and whether a separator can be employed for every well completion; and (2) the appropriate relationship of the separator in the context of our requirements that cover a very broad spectrum of wells."

EPA provides no additional details regarding the types of wells or particular "characteristics of the reservoir" for which a separator is not needed, including whether or not the wells in question are oil wells. Without additional details, it is not possible to thoroughly evaluate these claims. Critically, EPA has not provided any emissions data from completions on these wells where a separator is supposedly not needed. Moreover, the issue of whether or not a separator is "needed" is irrelevant – EPA has determined that the BSER for well completions is the use of REC separation equipment with combustion. In the proposed rule, EPA states that "combustion alone would not represent the BSER for well completions because, although the emissions reduction would be equal to the REC and completion combustion device combination (i.e., 95 percent control), the opportunity to realize gas recovery would be minimized and the generation of secondary combustion related emissions would be increased." In other words, EPA has already determined that forgoing the use of a separator is not BSER.

The practice described by EPA in section VIII.F.3 for which a separator is not needed, whereby operators, "direct the flowback to a pit and…combust gas contained in the flowback as it emerges from the pipe" is precisely the practice that RECs are designed to replace. In fact, this completion practice is the same as that described in EPA's Natural Gas STAR "Lessons Learned" fact sheet for RECs, as the problematic completion practice that leads to high emissions:

Typically, the gas/liquid separator installed for normal well flow is not designed for these high liquid flow rates and three-phase (gas, liquid and sand) flow. Therefore, a common practice for this initial well completion step has been to produce the well to a pit or tanks where water, hydrocarbon liquids and sand are captured and slugs of gas vented to the atmosphere or flared. Completions can take anywhere from one day to several weeks during which time a substantial amount of gas may be released to the atmosphere or flared.

Operators must not be exempted from the REC requirements simply on the basis that they choose not to employ a separator for reasons unrelated to emissions reductions, as EPA has already determined in its BSER analysis. Although it may not be possible for a separator to be employed for every well completion due to technological reasons such as gas quantity or pressure, the proposed rule already excuses operators from performing a REC in situations in which it is technologically infeasible for a separator to function.

Response: The EPA disagrees with the commenter that the rule exempts operators from conducting RECs simply on the basis that they choose not to employ a separator. On the contrary, the final rule states that a separator must be onsite during any non-exploratory, non-delineation and non-low pressure well completion and that attempts to use the separator be documented. The technical infeasibility exemption requires the operator to evaluate all available beneficial uses of captured gas and document the reasons why the gas cannot be captured, or if it can be captured, why it cannot be used for beneficial purposes.

Commenter Name: Lee Fuller, Executive Vice President, and V. Bruce Thompson, President
Commenter Affiliation: Independent Petroleum Association of America (IPAA) and the American Exploration and Production Council (AXPC)
Document Control Number: EPA-HQ-OAR-2010-0505-6983
Comment Excerpt Number: 18

Comment: As with the proposed LDAR requirements, in its rush to promulgate regulations aimed at additional sources of VOCs and methane, EPA assumed that reduced emission completions (RECs) on oil wells are essentially the "same" as RECs on natural gas wells.

Based on the preamble discussion of undertaking of an oil well REC, EPA assumes the process is essentially the same, but this is not necessarily the case. While certain wells will have relatively clear initial and separation flowback stages like natural gas wells, there are instances where there is no separation flowback stage owing to the lack of gas or quality of gas such that operation of a separator is not feasible. On certain wells, the initial flowback stage is followed by directing the flowback immediately into the production battery. Perhaps more so than with RECs on natural gas wells, the various stages of flowback on oil wells can be difficult to clearly delineate, and the ability to utilize a separator is a function of engineering judgment. IPAA/AXPC supports the concept of identifying two stages of flowback, with no control placed on the associated gas with oil well completions during the initial flowback stage. However, there will be situations where certain oil well completions will not experience a separation flowback stage.

In the preamble discussion of the REC requirements for both subcategory 1 and subcategory 2 wells, EPA expressed a clear intention to allow for venting of emissions in lieu of combustion during periods when the flowback gas is noncombustible. This intent is particularly important for completions utilizing inert gas, such as nitrogen or nitrogen foam, instead of water as the medium for the fracturing process. The inert gases present in the flowback make the gas, for a period of time, "not of salable quality" and technically infeasible. The relevant provisions of the proposed regulations at 40 C.F.R. 60.5375a(a)(3) and 40 C.F.R. 60.5375a(f)(2) should be modified at the end of the provision to allow for venting when "it is technically infeasible due to inert gas concentration." The addition of this phrase at the end of the current proposed language would eliminate any ambiguity as to EPA's intent.

Response: We are aware that, for both gas well and oil well completions, there are situations where there may not be separation flowback stage because a separator cannot function. We believe the final rule, while requiring that a separator be on site for completions of subcategory 1 wells, provides adequate allowances for the owner or operator to document when it is infeasible to operate a separator. However, we have added a requirement in the final rule that a separator be on-site during the entirety of the flowback period at subcategory 1 (developmental) wells. However, the factors that lead to technical infeasibility may not be apparent until the time the well completion occurs or after-the-fact (i.e., the separator was unable to function, or gas was contaminated and not of salable quality or had characteristics prohibiting other beneficial use and therefore, the gas was combusted). By that time, it would be too late to provide the equipment, and, as a result, the well completion will go forward without controls. We evaluated but declined to adopt other comments' recommendation to require prior notification and case-by-case advance evaluation by a regulatory agency because they are impracticable considering the large number of completions, the wide geographic dispersion of the completions and the remote location of many well sites. Rather we have expanded recordkeeping requirements in the final rule to include: (1) the reasons for the claim of technical infeasibility with respect to all four options provided in §60.5375a(a)(1)(ii), including but not limited to, name and location of the nearest gathering line; capture, re-injection, and reuse technologies considered; aspects of gas or equipment prohibiting use of recovered gas as a fuel onsite; and (2) technical considerations prohibiting any other beneficial use of recovered gas on site.

We believe these additional provisions will support a more diligent and transparent application of the intent of the technical infeasibility exemption in the final rule. This information must be included in the annual report made available to the public 30 days after submission through CEDRI, allowing for public review of best practices and periodic auditing to ensure flaring is limited and emissions are minimized.

Similarly, we believe the above provisions apply equally to the situation detailed by the commenter in which an inert gas is used as the fracturing medium. Therefore, we do not believe it is necessary to amend §§60.5375a(a)(3) and 60.5375a(f)(2) as suggested by the commenter.

3.9 Compliance

Commenter Name: Patricia Karr Seabrook
Commenter Affiliation: Miller/Howard Investments, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6818
Comment Excerpt Number: 7

Comment: We support the requirement that oil and gas companies use or bring to market captured gas, instead of flaring it. For a number of processes covered by the proposed standards, operators can either capture gas for sale or for a beneficial use on-site, or burn the captured gas in a flare or incinerator. Capturing the gas for sale is generally preferable, since it reduces harmful pollution and avoids waste. In almost all cases, oil and gas companies can utilize the gas instead of flaring, if they properly plan and design their equipment. EPA must specify that the use of flares should be permitted only in exceptional situations where it is genuinely infeasible to capture the gas for sale or on- site use or to use zero-emitting equipment; and EPA must ensure that any flares burn as cleanly as possible.

Response: Based on our BSER analysis, we are requiring a combination of REC and combustion for subcategory 1 wells. REC, as defined in the final rule, includes the following options: 1) route to a gas line or collection system, 2) re-inject into a well or another well, 3) use as on-site fuel, or 4) use for another useful purpose that purchased fuel or raw material would serve. This definition for REC is the same as that in subpart OOOO which, in response to public comment, included options in addition to routing to a gas line.[6] All of these options achieve the same emission reduction. However, these options are not always technically feasible, in which event the only way to reduce emissions is combustion. Therefore, the final rule requires combustion when REC (as defined above) is technically infeasible. We believe that the final standards address the commenter's concern.

Commenter Name: Robert M. Gould
Commenter Affiliation: San Francisco Bay Area Physicians for Social Responsibility (SF Bay PSR)
Document Control Number: EPA-HQ-OAR-2010-0505-6819
Comment Excerpt Number: 13

Comment: Specify that the use of flares should be permitted only where it is genuinely infeasible to capture the gas for sale or on-site use or to use zero-emitting equipment; EPA must ensure that any flares burn as cleanly as possible.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6818, Excerpt 7.

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[6] For example, see page 35 of the 2012 RTC document: Docket ID EP-HQ-OAR-2010-0505-4546.

Commenter Name: John Robitaille
Commenter Affiliation: Petroleum Association of Wyoming (PAW)
Document Control Number: EPA-HQ-OAR-2010-0505-6854
Comment Excerpt Number: 15

Comment: Our first comment with respect to proposed EPA well completion requirements is that in Wyoming, state permitting is required for completions with hydraulic fracturing and these permits require reduced emission completions where feasible.

Consequently, as EPA allows for storage vessels, and as we recommend for leak detection below, EPA should exempt operators from well completion requirements for hydraulic fracturing if a well is already subject to an equivalent enforceable requirement by the state or other agency. Duplicative requirements are unnecessarily burdensome.

Response: Section 60.5365a(a)(1) states, "A well that conducts a well completion operation following hydraulic refracturing is not an affected facility, provided that the requirements of §60.5375a(a)(1) through (4) are met." Section 60.5375a(a)(1) through (4) specify the requirements for a REC. Thus, if the owner or operator conducts the well completion in accordance with §60.5375a(a)(1) through (4) (for example, in response to the Wyoming requirements cited by the commenter), then the well would not be an affected facility under subpart OOOOa. This provision will alleviate the duplicative requirements envisioned by the commenter.

Commenter Name: Eric Schaeffer, Sparsh Khandeshi and Adam Kron, Environmental Integrity Project (EIP) on behalf of Adrian Shelley III, Executive Director,
Commenter Affiliation: Air Alliance Houston et al.
Document Control Number: EPA-HQ-OAR-2010-0505-6953
Comment Excerpt Number: 23

Comment: EPA Must Strengthen the Reduced Emission Completion Requirements

A. EPA Must Remove the "Technically Infeasible" Exemption for Reduced Emission Completions or, if EPA Chooses to Keep the Exemption, the Agency Must Amend and Clarify It

As EIP stated in its comments with the larger coalition of environmental organizations, as noted above, the Proposed Rule's addition of reduced emission completion (REC) requirements for oil wells is a vast improvement over the 2012 rule's failure to include such requirements.

Commenters take the opportunity to here to highlight the fact that the Proposed Rule's "technically infeasible" exemption as currently stated may detract significantly from the overall value of REC standards, is vague in its terms, and largely unnecessary. In the Proposed Rule, EPA has identified four separate options for utilizing gas captured through RECs: operators may (1) "[r]oute the recovered gas from the separator into a gas flow line or collection system;

(2) "re-inject the recovered gas into the well or another well;" (3) "use the recovered gas as an on-site fuel source;" or (4) "use the recovered gas for another useful purpose that a purchased fuel or raw material would serve." Between these broad options to flaring and the fact states and industry have demonstrated the ability of operators to find alternatives to flaring during completions, Commenters urge EPA to remove the exemption.

Should EPA opt to keep the exemption, it must amend and clarify it to ensure that it is used as little as necessary and administered tightly. As stated in the coalition comments, EPA must clarify certain wording and definitional issues, while also adding provisions requiring submittal of claims and proof by operators claiming the exemption and directing EPA and state agencies to consider claims on a case-by-case basis. Finally, if EPA intends to use proximity as a criterion for determining technical feasibility, it should not consider it as the sole factor. The Agency should consult the detailed state databases cited above, require the consideration of other factors, and require the consideration of distance as it relates to multiple wells from both gathering lines and other capture technologies. At the same time, EPA should consider the availability of options for alternative forms of transportation and use on site or locally.

With these new REC requirements for oil wells, EPA has the opportunity to make important improvements to the oil and gas industry and achieve needed reductions in flaring. A clear, well-implemented, and effective standard is key to the success of the new rule.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6818, Excerpt 7.

Commenter Name: Eric Schaeffer, Sparsh Khandeshi and Adam Kron, Environmental Integrity Project (EIP) on behalf of Adrian Shelley III, Executive Director,
Commenter Affiliation: Air Alliance Houston et al.
Document Control Number: EPA-HQ-OAR-2010-0505-6953
Comment Excerpt Number: 24

Comment: EPA Must Adopt Requirements to Assure that Flares Used to Control Emissions from RECs Achieve 98-Percent Destruction Efficiency

Oil and gas wells flare a significant amount of gas during the completion stage. EPA and industry assume that flares achieve 98-percent destruction efficiency. Recent studies have shown that flares only achieve this level of control when the gas routed to the flare has sufficient heat value to burn. Studies of flares in the petrochemical and refining industry found that the average combustion efficiency was about 94 percent. Other studies have found that combustion efficiency of flares can vary between 50 and 90 percent. Based on these studies, actual emissions of methane and VOCs from flaring at completions can be up to three times higher than estimated. This is a particular concern for flaring at oil and gas wells during the initial completion because the gas may be mixed with other materials like sand and water that will prevent full combustion of the gas.

EPA recently addressed this issue in the refinery context by requiring the industry to install accurate monitoring to measure the heat value of the gas and controls to adjust the addition of steam to assure complete combustion. EPA should require oil and gas well operators to install similar monitoring and controls on the flares used to control emissions from well completions. Even if it is not possible to install the necessary controls, EPA must require the monitoring to evaluate the combustion efficiency of flares used in this sector. This data will help improve the agency's understanding of VOC and methane emissions from these flares.

Response: The EPA does not believe that the steam-assisted flares used at refineries that are the subject of the monitoring requirements cited by the commenter are comparable to the combustion control devices used at well sites to combust gas generated during the completion process. As the commenter points out, gas in the flowback following hydraulic fracturing is accompanied by other materials. Specifically, during flowback, high volumes of water, fracturing fluids, sand and gas emerge from the well in multiphase slug flow that can vary with time. As a result, the NSPS does not specify what type of combustion device must be used, and specifies that a "completion combustion device," a term that is very broad, and without specific requirement for combustion efficiency, be used when combustion is allowed for emissions control instead of performing a REC.

Commenter Name: John W. Mitchell
Commenter Affiliation: Kansas Department of Health and Environment (KDHE)
Document Control Number: EPA-HQ-OAR-2010-0505-6804
Comment Excerpt Number: 6

Comment: *Issue: NSPS Applicability Deadline*

For the new "green completion" requirements to reduce emissions at oil well sites, EPA has requested comment on whether a sufficient supply of completion equipment will be available for affected well sites by the proposed effective date - 60 days after the final rule is published in the *Federal Register*. KDHE suggests extending that timeframe to 120 days. This would allow KDHE time to conduct a more thorough effort to ensure industry understands the requirements and ensure exploration firms sufficient time to contract for the necessary completion equipment.

Response: Please see section VI.E.5 of the preamble to the final rule for a response to this comment.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 66

Comment: REC Equipment Availability

API has not had enough time to determine if there is adequate REC equipment available to handle the new requirements on hydraulically fractured oil wells. However, in the current low oil price environment, many operators are drilling oil wells, but delaying well completions until a later date. API estimates that by the time Subpart OOOOa is finalized, there could be a backlog of up to 10,000 drilled oil wells waiting to be completed that could overwhelm the REC equipment market during an oil price recovery. Therefore, API recommends that hydraulically fractured oil wells that have been drilled, but not completed by the effective date of the final rule, should be exempt from the requirements to conduct an REC. In reality, companies will likely conduct an REC if equipment is available and if feasible, but this exemption would allow the requirement for REC for hydraulically fractured oil wells to begin without a very large backlog of drilled wells that have not yet been completed. Otherwise, there could be many instances where a company is not able to find REC equipment and would be out of compliance. This will give REC equipment manufacturers and the oil and natural gas industry more certainty in understanding additional REC equipment needs in the future.

Response: Please see section VI.E.5 of the preamble to the final rule for a response to this comment. Further, we do not agree that the rule should exempt wells that have been drilled and not completed by the effective date of the rule. We cannot exempt wells solely based on date of drilling if the completion event takes place after the effective date of the rule as these wells would have the same emissions potential as wells drilled after the effective date.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 64

Comment: Phase-In Times are Unnecessary to the REC Requirements for Oil Wells.

EPA is soliciting comment on whether the well completion provisions of the proposed rule can be implemented on the effective date of the rule or whether a phase-in period is necessary. EPA states that it believes that there will be a sufficient supply of REC equipment available by the time the NSPS becomes effective. We concur with this statement and conclude that phase-in of the well completion provisions is not necessary.

Gas well operators have been complying with the full well completions provisions of the 2012 Oil and Gas NSPS for gas wells since January of this year, and data indicate that some operators have also voluntarily complied with the REC provisions prior to the full implementation date. Data from EPA's GHG Reporting Program show that while the total number of hydraulically fractured gas well completions dropped by nearly 30% from 2011 to 2014, the number of completions with REC has decreased by only 5% in that time period, meaning that the percentage of completions with REC has grown, from 51% of completions in 2011 to 67% in 2014. This indicates that oil and gas operators have been preparing to comply with the REC provisions of the 2012 NSPS and that sufficient equipment is available to perform RECs.

The slowdown in drilling and completion of gas wells also means that there is a surplus of REC equipment available, which can be shifted to completion of oil wells. Since the 2012 NSPS went into effect in August of 2012, the count of rigs drilling gas wells has dropped due to low gas prices from 484 rigs running the week of 8/17/2012 to 189 the week of 11/25/2015. While the number of rigs drilling oil wells initially grew during this period, from 1425 rigs running the week of 8/17/2012 to a high of 1609 the week of 10/10/2014, low oil prices have since caused the oil well rig count to also drop steeply, with only 555 rigs running the week of 11/25/2015 (Figure 8). The Energy Information Administration's (EIA) Short Term Energy Forecast (STEO) for November forecasts that monthly crude oil production, which began to fall in the second quarter of 2015, will continue to decline through late 2016. The International Energy Agency's (IEA) Oil Market Report for November similarly finds that US crude oil production has been declining, and forecasts that even steeper declines lay ahead. IEA's report also estimates that in October 2015 only 800 new wells were completed, which is less than half the number of wells completed in the same month a year earlier. Given these forecasts, there should be no short- to medium-term shortages of REC equipment, and industry will have sufficient lead time to construct additional REC equipment, if needed in the long-term.

[Figure 8; US Crude Oil and Natural Gas Rig Activity (Baker Hughes North America Rig Count) shows curve drawing of rig count over timer from 8/2012 through 11/2015]

Oil and gas operators have had more than two years to construct additional REC equipment since the 2012 NSPS was finalized in August 2012, and the requirements to perform RECs on gas wells went into effect in January 2015. This long phase-in time for gas wells, combined with the significant slowdown in drilling of both gas and oil wells, indicates that there should be sufficient REC equipment available when the new NSPS goes into effect, such that a phase-in time for performing RECs on oil wells is not necessary. Even if drilling rates rebound more quickly than predicted before the effective date of the rule, a phase-in time should not be necessary, given that REC equipment is relatively simple to construct and can be readily assembled when needed, as we described in our previous comments on the 2012 NSPS. In sum, a sufficient supply of REC equipment should be available by the effective date of the proposed rules, and therefore a phase-in time for the well completion provisions is not necessary.

Response: Please see section VI.E.5 of the preamble to the final rule for a response to this comment. We believe the drilling activity for oil wells is significantly higher than that of gas wells and that the level of activity is sufficiently volatile to warrant a phase in period to avoid the operators being at risk for noncompliance.

Commenter Name: Mike Gibbons, Vice President – Production
Commenter Affiliation: CountryMark Energy Resources, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-6241
Comment Excerpt Number: 6

Comment: We also do not believe that sufficient equipment will be available to purchase for well completions (Best system of emission reduction (BSER) as is noted on Page 12 of the proposed regulation). As we drill a new well, we will not know if the well will meet the proposed exemptions (currently recommended to be 300 SCF/bbl or 15 boe) until the well is completed. Without knowing what the oil well production will be until after the well is completed, we must have compliance equipment available prior to drilling every well. This requirement will increase the demand for equipment, and result in a shortage of equipment.

We estimate that a sufficient number Reduced Emission Completion (REC) equipment may not be available for up to 24 months after the final regulation is published to the Federal Register. Equipment manufacturers may be able to supply equipment to the regulated parties on a shorter schedule, but not without a measureable increase in the equipment cost due to overtime and material expediting costs.

Response: Please see section VI.E.5 of the preamble to the final rule for a response to this comment.

Commenter Name: Mike Gibbons, Vice President – Production
Commenter Affiliation: CountryMark Energy Resources, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-6241
Comment Excerpt Number: 54

Comment: EPA is requesting suggestions for alternatives to mitigate the short-term REC equipment shortage. We believe that our industry will have a shortage of more than REC equipment, which will impede compliance. Other requirements that we believe may not be available include certified combustion devices, qualified Professional Engineers, OGI equipment, and certified third-party survey companies. Below is a list of suggestions to mitigate these deficiencies.

- As stated above, we believe that our industry will require 24 months to be incompliance with this regulation. We request that the compliance date be changed from 60 days after publication in the Federal Register to 24 months after publication in the Federal Register.
- EPA could phase the implementation over the requested 24 month period by utilizing the developing a metric that couples the oil production and GOR.
- EPA could permit owners/operators to utilize flares or combustors that are not certified to 95% destruction during the 24 month implementation period, or not require 95% certified combustors to be implemented at all locations.
- Do not require third-party companies to perform surveys. We believe that this should be an option to owners/operators, but not a requirement.
- Do not require Professional Engineers to review drawings for new and modified facilities.
- Utilize the threshold from OOOO that a tank emitting less than 6 tons per year is exempt from complying with OOOO. If the tanks at a facility are exempt from OOOO compliance; then the associated well head(s) and support equipment are exempt from OOOOa compliance requirements.

Response: Please see section VI.E.5 of the preamble to the final rule for a response to this comment regarding potential REC shortage in the near term. See response to DCN EPA-HQ-OAR-2010-0505-6804, Excerpt 6 with respect to the compliance date for oil well completions. We believe the phase in of 180 days will be sufficient time to address the availability of REC equipment, combustion devices and qualified professional engineers. The final rule also allows a year for implementation of fugitive monitoring requirements which will allow more time to address any deficit in the availability of OGI equipment or contractors.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 30

Comment: Presently the falling and lower prices of both oil and natural gas have substantially decreased the level of drilling and completions across the nation.

[Graph - Weekly natural gas rig count and average spot Henry Hub; Data from Jan. 2007 through July 2015]

As a result, there will likely be adequate REC equipment and personnel available. Some service companies have laid workers off; 91,000 lay-offs have occurred within the United States. http://www.houstonchronicle.com/business/energy/article/Rising-layoffs-stun-worry-oilindustry-workers-6460142.php Should the United States experience an unexpected dramatic increase in prices which results in a completion boom, then we recommend that in the event there is a shortage of REC equipment and personnel that preference be given to those wells with greater emissions should REC equipment not be utilized. In other words, require REC equipment in those basins/wells where they will do the most good reducing the larger amount of emissions.

Response: Please see section VI.E.5 of the preamble to the final rule for a response to this comment.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 76

Comment: Industry also lacks the necessary equipment to roll out REC requirements nationwide in such a short implementation window. EPA should create a compliance phase-in period of at least 6 months. This phase-in timeline will give operators the flexibility to meet new requirements for any RECs involving specialized equipment. If there is no phase-in period, the REC requirements will be particularly burdensome for small operators. The lack of supply will drive up REC costs, which will not be absorbed as quickly by smaller entities. And these small entities will almost certainly lack the purchasing power of larger operators, thereby making it difficult to obtain the needed equipment before the compliance period begins.

Response: Please see section VI.E.5 of the preamble to the final rule for a response to this comment.

Commenter Name: Stuart A. Clark and Ursula Nelson, Co-President
Commenter Affiliation: National Association of Clean Air Agencies (NACAA)
Document Control Number: EPA-HQ-OAR-2010-0505-6932
Comment Excerpt Number: 10

Comment: *Applicability Deadline*

With respect to the new "green completion" requirements for emissions at oil well sites, EPA requested comment on whether a sufficient supply of completion equipment will be available for affected well sites by the proposed effective date: 60 days after the final rule is published in the *Federal Register*. NACAA believes that the proposed 60-day timeframe is reasonable and recommends its inclusion in the final rule.

Response: Please see section VI.E.5 of the preamble to the final rule for a response to this comment.

Commenter Name: J. Jared Snyder, Assistant Commissioner for Air Resources, Climate Change Energy
Commenter Affiliation: New York State Department of Environmental Conservation (DEC)
Document Control Number: EPA-HQ-OAR-2010-0505-7006
Comment Excerpt Number: 10

Comment: EPA requested comment on applicability deadlines for the new green completion requirements for emissions at oil well sites. The DEC supports EPA's deadline of 60 days after the final rule is published in the federal register as a reasonable deadline.

Response: Please see section VI.E.5 of the preamble to the final rule for a response to this comment.

Commenter Name: Kari Cutting
Commenter Affiliation: North Dakota Petroleum Council (NDPC)
Document Control Number: EPA-HQ-OAR-2010-0505-6789
Comment Excerpt Number: 24

Comment: EPA has requested comments on specific criteria that could help clarify the availability of gathering lines, as well as any other factors that could be specified in the NSPS for requiring recovery of gas from well completions. Due to the significant and rapid development of the Bakken and the rural and far-flung nature of well-site locations, a significant (but significantly decreasing) portion of associated gas emitted from wells is not routed to a gathering sales line due to technical infeasibility. Thus, operators in North Dakota must combust the gas. In the preamble to Proposed NSPS OOOOa, EPA specifically acknowledges that "[a]vailability of a gathering line is one consideration affecting feasibility of recovery of natural gas during completion of hydraulically fractured wells." In North Dakota, this technical infeasibility occurs for several reasons, including but not limited to:
• the ability of owners and operators to obtain rights-of-way to cross properties (in many cases the surface areas are managed by multiple stakeholders both private and public);
• the distance from the well to an existing gathering line (the majority of operations are located in rural areas);
• the capacity of an existing gathering or transportation line to accept additional throughput (as infrastructure limited in the state);
• the overall cost-effectiveness of installing pipeline infrastructure; and
• third parties control of pipelines in the state that can impose operational or contractual terms that render connections infeasible.

Importantly, in the Bakken, bringing both gathering and transportation lines in is problematic due to the delay in authorizations from federal land managers, as approvals for gathering lines lag far behind well site development where gathering line approvals from federal land managers can take more than three years. Additionally, gathering system pipelines for transportation of natural gas associated with crude oil production are in many cases operated by a third party; as such, the availability of such pipelines is beyond the control of the producer.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6789, Excerpt 11.

Commenter Name: J. Roger Kelley
Commenter Affiliation: Domestic Energy Producer's Alliance (DEPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6793
Comment Excerpt Number: 10

Comment: EPA has requested comments on specific criteria that could help clarify the availability of gathering lines, as well as any other factors that could be specified in the NSPS for requiring recovery of gas from well completions.

For example, in North Dakota it is infeasible for most operators to tie into a gathering line for several reasons, including but not limited to:

- the ability of owners and operators to obtain rights-of-way to cross properties (in many cases the surface areas are managed by multiple stakeholders both private and public);

- the distance from the well to an existing gathering line (the majority of operations are located in rural areas);
- the capacity of an existing gathering or transportation line to accept additional throughput (as infrastructure limited in the state);
- the overall cost-effectiveness of installing pipeline infrastructure; and
- third parties control many pipelines in the state and can impose operational or contractual terms that render connections infeasible.

Importantly, in the Bakken, bringing both gathering and transportation lines in is problematic due to the delay in authorizations from federal land managers, as approvals for gathering lines lag far behind well site development where gathering line approvals from federal land managers can take more than three years. Additionally, gathering system pipelines for transportation of natural gas associated with crude oil production are in many cases operated by a third party; as such, the availability of such pipelines is beyond the control of the producer. Furthermore, many of the wells in the Bakken are oil wells that do not have sufficient well pressure or gas content during the well completion to tie into gathering lines.

Due to these varied factors, the DEPA respectfully requests that EPA deem the use of REC "technically infeasible" where production is not tied to a gathering line under the following situations:

- low pressure or low gas content;
- midstream delays that are beyond the operator's control;
- longer negotiation periods due to lack of eminent domain;
- line/capacity issues (as a result of continued expansion of development);
- force majeure; or
- where curtailment would be unreasonable due to reservoir damage and oil royalty discontinuation for gas capture reasons.

Establishing a bright line for overall feasibility of conducting REC for oil wells is not practical due to the varied scenarios that may occur. Owners and operators should have the flexibility, based on technical, economic and other factors, to use a completion combustion device to reduce methane and VOC emissions from hydraulically fractured oil well completions under the scenarios described above.

Due to the unique circumstances as in those described above, EPA should accommodate additional exemptions for certain oil well completions.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6789, Excerpt 24.

Commenter Name: C. William Giraud
Commenter Affiliation: Concho Resources Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6847
Comment Excerpt Number: 11

Comment: Over the past two years Concho has installed three gas gathering line systems in New Mexico. For each of these gathering lines, gas enters the line from several Concho tank batteries, is transported through the Concho gas line, and is then delivered to a gas line operated by a third party gas gathering/processing company. In each of these three Concho lines, availability or capacity exists for additional volumes of gas, however, the third party line is usually at capacity and has high operating pressure that prevents or restricts delivery of all the gas Concho produces. This necessitates flaring at Concho batteries because the third party is unable to accept all the gas we have available for delivery.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6789, Excerpt 24.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 63

Comment: API Agrees That The Lack Of A Flow Line/Gathering System Meets The Criteria Of Technical Infeasibility In 60.5375a(1)(Ii).

EPA states in the preamble on page 56631:

"There may be cases in which, for reason(s) not within an operator's control, the well is completed and flowback occurs without a suitable flow line available. We are aware that this situation may be more common for wells that are primarily drilled to produce oil. In those instances, § 60.5375(a)(3) requires the combustion of the gas unless combustion poses an unsafe condition as described above."

Before natural gas production can be sent to natural gas gathering line, all of following must be done:

A natural gas gathering line/system must be permitted, installed and operational in the area.

Permits are required for right-of-way, installation, compressor site air quality, etc. for the natural gas gathering line/system before it is installed, which take much longer than getting a permit to drill a well. Designing and installing a natural gas gathering system (including pipelines, compression, gas plant to send the gas to, etc.) takes considerable time and money. Furthermore, designing and installing a gas gathering line depends on having enough natural gas production to justify the exceptional cost and burden for the gas gathering system.

A contractual right to flow into the gas gathering system must be agreed to with the company that owns the gathering line. In most cases the company owning the well is different from the company that owns the gathering system. Therefore, contracts must be put in place to allow for flow to the gathering system. The company owning the gas gathering system must determine if the pipeline has the capacity to accept the additional well or wells being added.

Necessary permits and right of way must be obtained for the pipeline from the well site to the natural gas gathering system. Permits and right-of-way are required for installation of the pipeline to connect to the natural gas gathering system. Sometimes obtaining the necessary right-of-way can be difficult and may require a court order.

The natural gas must meet the specifications of the natural gas gathering line. Contracts with the gathering company include specifications for entering the gas gathering line including concentrations of inert gases such as carbon dioxide or nitrogen, and hydrogen sulfide. Carbon dioxide and nitrogen are often used to energize well stimulations to assist with flowback and cleanup. The carbon dioxide and nitrogen flowback and cannot be routed to the pipeline because they make the gas not salable. The natural gas gathering system operator ultimately controls when an operator can send gas to sales.

There must be adequate reservoir pressure to flow into the natural gas gathering line to clean up the well and not choke it. When each stage of a stimulation program is initially completed, the pressure of the gas may not be high enough to overcome pipeline pressure and maintain adequate velocity to cleanup the well and reservoir. Any time this occurs, the well must be flared or vented until enough flowing pressure is available to send gas to the sales pipeline. This allows clean-up of the well bore and is critical to minimize the potential for formation damage. It is possible that sensitive zones can lose productivity due to increased clean-up time required if back pressure is added to the well because of the line pressures. Once a fracture stimulation is pumped, flowback and cleanup must proceed regardless of sufficient pressure to enable sales or severe and permanent reservoir damage is likely. Adding compression to overcome line pressure on low energy wells has been tried several times and found to be not feasible for technical reasons. Furthermore it adds additional emissions for engines to power the compressors while greatly increasing the cost.

The natural gas gathering line must be operational at the time of the completion. Natural gas gathering lines can be down for a multitude of reasons including but not limited to compressor maintenance or repair, line maintenance, line inspection, the gas plant being shut down, etc.

A gas gathering system with sufficient capacity must be in place. Gas that is produced from an oil well but can't be sold is known as "stranded" gas. It's stranded because the pipeline infrastructure needed to gather and transport the gas for processing is not available. Unlike gas fields where infrastructure may be unavailable in limited situations such as exploration, delineation, or some leasehold wells, gas gathering infrastructure can be unavailable for oil wells across an entire field or area. Lack of available infrastructure occurs for various reasons. For instance, insufficient associated gas production volumes may make it uneconomic to gather, process, and sell the produced gas. Or, economic gas gathering infrastructure construction may lag behind the start of new well production, as currently occurs in the Bakken oil shale formation of the Williston Basin in North Dakota. During flowback and continuing into production, stranded gas from high pressure wells such as those in the Bakken is flared for both reasons of safety and VOC emissions reduction.

While it's imperative that a gas gathering system must be available for a REC, the gathering system must also have the capacity to collect the volume of gas produced during a REC at a flow rate sufficient to clean out the well. Gas gathering systems are designed to accommodate the maximum anticipated flow rate and pressures during the production phase of wells, not necessarily the flowback phase. While this could also be a potential issue for certain gas wells, it's a known issue in the Bakken oil shale where limited gas gathering infrastructure exists. Flowing wellhead pressures are high (e.g., 4000 psi), and gas volume during initial flowback can spike at a rate many times higher than the flow rate when the well is turned over to production.

Where gathering systems exist, sending all the initial gas volume from flowback through the gathering line without properly choking the flow to prevent exceeding the gathering line capacity may cause an upset somewhere downstream because of over pressuring the system. Any major upset has the potential to result in a serious safety and/or environmental incident. Choking the flowback to meet gas gathering capacity can cause poor flowback velocity which inhibits proper cleanout of the well. Consequently, a partial REC might be feasible as some of the flowback gas may be able to be sent to sales, but remaining gas would need to be flared so as to not overpressure or exceed the capacity of the gathering system.

Furthermore, there are many reasons to complete a well and flowback without a natural gas gathering line or production equipment in place including but not limited to:

- **Avoiding lease jeopardy by establishing production in paying quantities**. Mineral leases contain expiration clauses tied to specific milestones to encourage the development of a lease hold in a timely fashion. One of the typical milestones is performance of a well completion. If the date is missed, the lease expires, causing the rights owner not only to lose the cost of the lease, but the investment in assessing the lease and preparing to drill it. It is common for operators in a low-price natural gas environment to drill and complete a well prior to acquiring surface equipment or contracting for gathering system space. Delays due to unavailability of REC equipment create an additional risk that the operator could fail to live up to steps in the contract and negate the contract causing the operator to lose their rights to the minerals.
- **Not knowing the composition of gas in advance limits the ability to design the production equipment or pipeline.** In some areas, the production equipment and pipeline are not installed until the composition of the gas is known in order to design the equipment to handle the gas and condensate, particularly for sour gas fields where the level of H2S is critical for the design requirements. This is particularly significant in areas where the reservoir and properties are not well known and delineated.
- **The surface rights must be obtained for installing production equipment.** In many cases the owners of the mineral rights are different from the surface rights; therefore, surface rights must be obtained for construction of a pad to drill a well and subsequently install the production equipment. These surface rights are size/area limited and in many cases not sufficient to have in place both the completions equipment and the production equipment at the same time so companies wait to install the production equipment until

after the drilling and completions equipment are gone. This also limits the "footprint" of surface disturbance to the area.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6789, Excerpt 24.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 73

Comment: In other instances, particularly in areas like North Dakota, gas gathering and processing infrastructure exists, but lacks capacity. This is particularly true where new development has occurred without pre-existing infrastructure. Where it is practical, producers will nearly always develop in areas near gas gathering systems. This allows maximum economic and environmental benefits. But it is not always practical to develop near this infrastructure—especially in very remote areas (such as certain parts of North Dakota). Producers do not always have control over how gas gathering infrastructure is used. For example, in some cases, midstream companies may curtail the capacity made available for an operator's associated gas or other constraints. In others, lease terms and other constraints require the resource to be developed on a certain timeline despite dedicated infrastructure. The REC rules must account for these inherent uncertainties and difficulties; or the rule risks shutting down significant portions of this industry, which is already unduly strained by low commodity prices. Such consequences are likely to be borne disproportionately by smaller producers.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6789, Excerpt 24.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 74

Comment: Further complicating matters, some wells may come online with a high initial production (IP) rate. In these instances, the large volumes of associated gas produced may overwhelm limited gas supply capacity. Operators are left with little choice but to flare that associated gas or risk damage to the reservoir of a highly productive oil well by choking it back. That could have significant economic consequences for operators as well as mineral owners, including the federal government. The final rule must consider these consequences in its economic analysis of RECs. We recommend the final rule defers to operator knowledge to determine when green completions are feasible.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6789, Excerpt 24.

Commenter Name: Cory Pomeroy, General Counsel
Commenter Affiliation: Texas Oil & Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-7058
Comment Excerpt Number: 56

Comment: EPA solicits comment on criteria that could help clarify availability of gathering lines, stating that availability of a gathering line is one consideration affecting feasibility of recovery of natural gas during completion of hydraulically fractured wells and that there are several factors that can affect availability of a gathering line including, but not limited to, the capacity of an existing gathering line to accept additional throughput, the ability of owners and operators to obtain rights of way to cross properties, and the distance from the well to an existing gathering line. EPA notes that Montana allows gas from wells to be flared only in cases where the well is farther than one-half mile from a gas pipeline and solicits comment on whether distance from a gathering line is a valid criterion on which to base requirements for gas recovery and, if so, what would an appropriate distance for such a threshold as well as on any other factors that could be specified in the NSPS for requiring recovery of gas from well completions. Further, EPA solicits comment on:

> whether distance from a gathering line is a valid criterion on which to base requirements for gas recovery and, if so, what would an appropriate distance for such a threshold. In addition, we solicit comment on any other factors that could be specified in the NSPS for requiring recovery of gas from well completions.

As noted by EPA, there are numerous technical and other factors contributing to the complexity and overall feasibility of conducting REC.

Regarding gathering pipeline availability, development of surface equipment and pipeline infrastructure may lag behind well completion schedules for many reasons. Wells may be drilled, completed using hydraulic fracturing and then shut in for a time. Operators may be obligated to put an oil well on production before a gas pipeline is in place in order to hold the lease. Wells may flow back for an extended period to prove technical and/or economic viability of producing the well to surface equipment. New oil wells may produce unexpected volumes of associated gas.

Availability of gathering system pipelines is most often out of the control of the producer. Gathering system pipelines that would be used for REC and sales of natural gas are in many cases operated by a third party. There are right of way issues when crossing private, tribal, state or federal lands administrated by the Bureau of Land Management that can take years to resolve. Contractual issues may also arise. An existing pipeline may be at or near capacity, affecting reliable availability. There may be multi-jurisdictional issues for sites located near the boundary of Indian Country.

Feasibility of routing recovered gas from a well completion flow back to a gas gathering system pipeline cannot hinge on an arbitrary distance from the well to that pipeline or any other threshold criteria. Each and every well presents unique circumstances related to reservoir characteristics, surface conditions and numerous technical and non-technical factors.

The cited Administrative Rules of Montana, ARM 17.8.1603, apply to production, not to hydraulically fractured well completions. ARM 17.8.1603(a) requires

> volatile organic compound (VOC) vapors greater than 500 British thermal units per standard cubic foot (BTU/scf) from oil and gas wellhead equipment must be routed to a gas pipeline, or, if a gas pipeline is not located within a 1/2 mile of the oil and gas well facility, VOC vapors greater than 500 BTU/scf must be captured and routed to emissions minimizing technology or to a smokeless combustion device equipped with an electronic ignition device or a continuous burning pilot system; . . .

Montana's requirement is based on the intrinsic properties of the produced gas (heating value, BTU/scf) and not the volume produced. As a consequence, even crude oil wells producing very small amounts of associated gas would be required to compress and pipe such gas to a local pipeline. The technical and economic feasibility of meeting ARM 17.8.1603(a) aside, EPA should not require producers to connect to a pipeline gathering system purely based on an arbitrary linear distance to such system. As noted above, pipeline gathering systems are typically owned and operated by an entity other than the producer. Also as discussed above, there are many factors considered in whether or not connection to an existing pipeline is feasible.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6789, Excerpt 24.

Commenter Name: Mike Gibbons, Vice President – Production
Commenter Affiliation: CountryMark Energy Resources, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-6241
Comment Excerpt Number: 50

Comment: Many of the oil producers in the Illinois Basin do not process and sell gas that is associated with oil production because the processing costs are high relative to the volume of associated gas and because interstate pipelines are not readily accessible to the operators. Figure 4 (source: USGS) shows a map of the Illinois Basin and Figure 5 (source: EIA) shows Interstate and Intrastate natural gas pipelines in Indiana and Illinois.

Figure 4. Illinois Basin

Figure 5. Illinois and Indiana Natural Gas Pipeline

Most of the oil wells do not have reasonable access to interstate or intrastate pipelines to transport produced gas to market. The cost to purchase right of way, install gas pipelines, tie into transportation pipelines, and install custody transfer instrumentation exceeds the economic benefit of selling the gas.

Our interpretation of the proposed regulation is that EPA assumes that installing a gas gathering pipeline is relatively low cost and that Right of Way is easy to procure. Our experience is that pipelines are expensive to install and maintain and acquiring Right of Way ranges from easy to difficult.

Some land owners are accommodating while other land owners have no interest in having any type of pipeline on their property. The ability to secure Right of Way has significantly impacted projects ranging from additional cost to project cancelation. The effort and cost to secure Right of Way should not be underestimated for any type of pipeline project.

In addition to the cost of the pipeline and Right of Way risks, most of the gas that is produced in the Illinois Basin does not meet Interstate pipeline quality without subsequent purification. Nitrogen, carbon dioxide, water, hydrogen sulfide, and heavy hydrocarbons must be removed before the gas meets interstate pipeline specifications. All of this processing is expensive to acquire, install, and operate the equipment. If the cost of the pipeline and Right of Way access did not eliminate a project to sell gas, the cost to make the gas pipeline quality usually does eliminate a project from consideration.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6789, Excerpt 24.

Commenter Name: Erik Schlenker-Goodrich
Commenter Affiliation: Western Environmental Law Center (WELC)
Document Control Number: EPA-HQ-OAR-2010-0505-6871
Comment Excerpt Number: 4

Comment: Criteria to help define the availability of gathering lines

As part of the rulemaking process, the EPA has asked for comment "… on criteria to help define the availability of gathering lines, such as distance from the well, capacity to accept additional throughput, and owner/operators' ability to obtain rights of way to cross properties."

This request for comments was made specifically in the context of green completion requirements for natural gas well sites and oil wells sites and equipment used in oil production in regards to the availability of gathering lines to move natural gas to market as an alternative to flaring. We believe that the availability of gathering lines is also relevant to methane emissions from any equipment or practice where emissions can be flared, including pneumatic pumps, storage tanks and pipeline maintenance.

Unlike most methane pollution control technologies, natural gas gathering pipelines are a system-wide investment by owner/operators rather than a specific piece of equipment or operating practice to address specific methane emission sources. According to the Energy Information Administration, "A natural gas pipeline system begins at a natural gas producing well or field. In the producing area many of the pipeline systems are primarily involved in "gathering" operations. That is, a pipeline is connected to a producing well, converging with pipes from other wells where the natural gas stream may be subjected to an extraction process to remove water and other impurities if needed."

Accordingly, the EPA criteria should approach gathering lines for any individual well site as part of a system for new and modified oil and gas wells and other methane emissions sources. This is particularly important for the cost assumptions used in regulatory impact analysis and the methodology established for granting exemptions "if it is not feasible to get the gas to a pipeline."

We concur with green completion exemptions for exploratory/wildcat wells and delineation wells given their geographic dispersion and limited overall production. However, in these cases, the EPA should adopt clear and transparent definitions and award exemptions based on strict adherence to these definitions.

For production/infill wells, the EPA should adopt a system-wide approach to criteria for defining the availability of gathering lines, including distance, capacity and rights of way. The EPA should identify average costs for connecting wells, boosting well pressure, expanding pipeline capacity, acquiring rights of way, and other parameters based on the design of field-level systems rather than costs for individual wells. Fundamentally, owner/operators should not be rewarded for poor planning, or decision-making based on well profitability at the expense of the public interest in curbing methane pollution.

A system-wide approach must also be taken with tests of the "feasibility" of getting gas to a pipeline. Owner-operators should be required to provide actual costs forecasts for wells based on how they fit into their field-wide development planning. A well by well approach that ignores a well's relationship to a gathering system (and in some cases multiple gathering systems proximate to a well) will ignore the economies of scale available from system-wide investments made for multiple wells.

There are several examples of this approach. BLM's Oil and Gas Onshore Order 1 requires field-wide drilling plans as part of applications for permits to drill. Colorado has authority to limit production in a field or pool to limit waste. North Dakota requires gas capture planning in applications for permits to drill which must include detailed gas gathering pipeline system maps and proposed well tie-ins. In establishing criteria for the availability of gathering lines or tests of economic feasibility, the EPA should look closely at these approaches in developing criteria for obtaining accurate costs for individual wells.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6789, Excerpt 24.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance

Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 70

Comment: The gas-gathering infrastructure in the West (particularly on federal lands) is already under immense stress, and the proposed regulations would greatly increase the burdens on operators and gas gathering companies. The process to permit gathering line right-of-ways (ROWs) on federal lands is often a frustrating and time-consuming process, and it can sometimes take years before an operator receives construction approval. In these situations, operators are left with no choice but to flare associated gas from production. EPA should work with its federal agency partners to provide operators with a reliable, predictable, *and timely* permitting process. This would offer economic and environmental benefits to operators as well as the public.

The following provides additional details of the process required to obtain approval for pipeline construction on property subject to National Environmental Policy Act (NEPA) jurisdiction, which includes the Fort Berthold Indian Reservation. The timeline is based on an aggregation of actual projects.

1. Obtain permission to survey (PTS) from landowners and submit to BIA (Bureau of Indian Affairs) New Town office for approval. ***(4 weeks)***
    - a. Responsible party: operator's land agent
2. "Soft stake" the pipeline centerline after PTS has been granted by BIA (surveying company/engineers). ***(1 week)***
    - a. Responsible party: surveying company and/or contracted engineer
3. Schedule Environmental Assessment (EA) onsite. ***(1 week)***
    - a. A representative from the BIA-New Town office must be present.
    - b. Consultants conduct natural and cultural surveys.
4. Prepare final plans. ***(3 weeks)***
    - a. Responsible party: surveying company and/or contracted engineer
5. Prepare and send scoping letter for approved pipeline (if applicable, for trunk lines only, lateral lines to well locations will not require scoping). ***(4 weeks)***
    - a. Responsible party: consultants
    - b. The EA cannot be submitted until the end of the 30-day comment period
6. Schedule ROW onsite with the BIA-New Town office. ***(1 week)***
    - a. A representative from the BIA New Town office must be present
    - b. Responsible party; Operator
7. Prepare EA and cultural reports; from initial surveys conducted in step 3. ***(12 weeks)***
    - a. Responsible party: consultants
    - b. Submit cultural reports to the BIA before the EA is submitted. Unless the THPO office clears the report sooner, there is a 30-day waiting period before the BIA in Aberdeen will review the EA
8. If habitat for a listed endangered/threatened species is present, an informal consultation with the US Fish and Wildlife Service (USFWS) is required. Project must receive concurrence from USFWS. ***(8 weeks or longer)***
9. Submittal of EA to BIA Aberdeen office and Finding of No Significant Impact (FONSI) is reached. ***(4 weeks)***
    - a. Responsible party: consultants

   - b. There is a 30-day notice period after the FONSI is issued
10. Pipeline Company obtains landowner signatures agreeing to terms and payment. These signatures are then filed in the ROW application that is submitted to the BIA New Town office for approval. ***(4 weeks)***
   - a. Responsible party: Pipeline company land agents
11. Construction operations can begin only after the BIA issues a Notice to Proceed and ROW grant. ***(5 weeks)***

The above-described times for completion of each stage will vary depending on: BIA onsite schedule, completeness of supplementary information, results of resource surveys, results of on sites, completeness of application packages, public response to projects, weather conditions, and, of course, securing proper consents from all necessary landowners.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6789, Excerpt 24.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 71

Comment: Where the proposed rule solicits comment on criteria that could help clarify availability of gathering lines (80 Fed Reg. at 56,634), we suggest one criterion that could be used to define capacity to accept additional throughput is hydraulic modeling results. Hydraulic modeling of the gas gathering system and of new connections is typically done in advance of oil well/associated gas completions. If the hydraulic modeling results indicate that less the full amount of estimated gas production at flowback can be accepted into the gathering pipelines, then a combination of recovery and combustion should be allowed.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6789, Excerpt 24.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 32

Comment: Gathering line distance is a valid criterion on which to base requirements regarding well flaring. We advocate a prudent approach for the EPA's regarding the flaring of wells during the completion process. We recommend allowing wells to be flared only in cases where the well is farther than one mile from a gas pipeline. Generally, pipeline availability is definitely problematic in a developing oil and gas field. However, the operator also has the option to delay flaring until gathering lines are available.

Response: The EPA appreciates the input from the commenter concerning the distance from a gathering line as a criteria for feasibility of natural gas recovery. Based on the comments received on this topic, we understand that there are a number of considerations in addition to distance that determine the feasibility of routing recovered natural gas to a gathering line. Due to the complexity of this issue, we are not finalizing requirements for determining feasibility of routing recovered natural gas to a gathering line based on distance to the gathering line.

Commenter Name: C. William Giraud
Commenter Affiliation: Concho Resources Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6847
Comment Excerpt Number: 12

Comment: Based upon Concho's experience laid out above, we encourage the EPA to adopt criteria other than just distance from a gathering line for requiring gas recovery. The EPA should also consider whether it is economical for either an operator or gatherer to build the line. A 4" line on the surface may cost $50,000 to $60,000 per mile to build but has a limited capacity. This is in contrast to a high pressure buried steel line which costs approximately $500,000 per mile. The 4" surface line has the potential to be economical in a year, averaging 100 Mcfd/mile, whereas the buried high pressure line would only be economical within a year at 700 Mcfd/mile. Thus, a three to five mile line requires a group of highly productive wells to be economical. The producer or gatherer also needs to know the planned productivity of the wells proposed to be drilled in an area before they invest in miles of buried line.

Additional criteria the EPA should use in determining whether to require gas recovery includes the gas flow rate in an area; distance of course; size of pipe; type of pipe material; whether compression, dehydration or treating are required; whether the line must be buried; and the quality of the gas. For instance, some gas may have a high hydrogen sulfide content and must be burned because it cannot be safely processed by the existing infrastructure. Due to these other considerations, Concho recommends that if this proposed rule is adopted the EPA should include a table establishing thresholds for distance versus gas recovery flow rate.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6787, Excerpt 32.

Commenter Name: Lee Fuller, Executive Vice President, and V. Bruce Thompson, President
Commenter Affiliation: Independent Petroleum Association of America (IPAA) and the American Exploration and Production Council (AXPC)
Document Control Number: EPA-HQ-OAR-2010-0505-6983
Comment Excerpt Number: 18

Comment: IPAA/AXPC agrees that the feasibility of oil RECs should take into consideration the availability of gathering lines and that it is not as simple as a linear distance from a gathering line. As EPA acknowledges in the preamble, there are many factors that determine gathering line availability – not just distance. There are other considerations that drive the decision to recover gas which include, but are not limited to, the following factors: gas volume, gas pressure, gas Btu content, gas liquid content, sales line gas pressure requirements, moisture requirements, compression, and current takeaway capacity of existing gathering systems. One workable approach that might assist regulators is to use a linear distance, such as a ¼ mile, to presume that flaring is permitted because it is generally agreed that, beyond that distance a gathering line is not available. The converse, a gathering line within a ¼ mile, should not be assumed to be available prompting a case-by-case determination based on the factors detailed above. Again, IPAA/AXPC supports EPA's acknowledgment that the availability of a gathering line must be considered in evaluating the feasibility of an oil well completion but that it is not as simple as designating a linear cut point.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6787, Excerpt 32.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 64

Comment: Distance To The Gathering Line Is Not A Valid Criterion On Which To Base Requirements For Gas Recovery.

Sufficient natural gas production in the area is required to justify the cost and burden for permitting, designing, and building the natural gas gathering system. Before gas can be routed to a gas gathering line, all the following must be done:

- A natural gas gathering line system must be permitted, installed and operational in the area a reasonable distance from the well.
- A contractual right to flow into the gas gathering system with the company that owns the gathering line must be in place.
- The necessary permits and right-of-way for the pipeline from the well site to the natural gas gathering system must be obtained.
- The natural gas must meet the specifications of the natural gas gathering line.
- There must be adequate reservoir pressure to flow into the natural gas gathering line to clean up the well against the pipeline pressure without lowering the flow and velocity to the point where the well will not adequately clean-up.

Furthermore in the preamble EPA has solicited comment on criteria that could help clarify availability of gathering lines (FR 56634), and specifically mentions *"that some states require collection of gas if a gathering line is present within a specific distance from the well. For example, Montana allows gas from wells to be flared only in cases where the well is farther than one-half mile from a gas pipeline.*

EPA may have misinterpreted the cited Montana regulation: "(2) The owner or operator of an oil and natural gas well facility shall operate the air pollution control equipment and comply with the air pollution control practices required in (1) from the initial well completion date for the facility until the department decision on the permit application is final. (Emphasis added) Therefore, this control equipment requirement applies from the "initial well completion date for the facility" until a decision is made on a permit application. The term "initial well completion date for the facility" is not defined in the section referenced by EPA. However, if you look at the history of this regulation (prior regulation 75-2-211), the term means:

"For purposes of this section, the initial well completion date for an oil or gas well facility is:

(i) For an oil or gas well facility producing oil, the date when the first oil is produced through wellhead equipment into lease tanks from the ultimate producing interval after casing has been run: and

(ii) For an oil or gas well facility producing gas, the date when the oil or gas well facility is capable of producing gas through wellhead equipment from the ultimate producing interval after casing has been run.

Therefore, the Montana regulation appears to only apply from the date a well is producing oil and natural gas to lease sales (what EPA describes as the production phase) and not during flowback from hydraulically fractured completions.

In addition to the issues with gathering line permitting and availability outlined in detail above, there are many situations that would disallow legal access to a gathering system even if an existing gas pipeline was less than one half mile from a well including but not limited if the land between the well and pipeline is designated wetland, the presence of endangered species has been identified, landowner disputes, and archeological issues.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6787, Excerpt 32.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 72

Comment: The proposed rule also solicits comment on whether distance from a gathering line is a valid criterion on which to base requirements for gas recovery. 80 Fed Reg. at 56,634. The Alliance contends that distance to gathering lines alone is not a valid criterion. [Right-of-way] ROW delays impact short and long distance connections equally; there may not be gathering pipe available during flowback due to ROW delays. Also distance does not consider whether there is capacity to accept additional throughput. The distance to a gathering pipeline may be short, but there may be no capacity to accept additional throughput. Recovering gas in this situation is technically infeasible.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6787, Excerpt 32.

Commenter Name: Michael Turner, Senior Vice President, Onshore
Commenter Affiliation: Hess Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6960
Comment Excerpt Number: 7

Comment: EPA Should Not Complicate the Definition of infeasibility

If EPA does not accept state determinations of technical infeasibility or a 14-day exemption for flowback flaring, Hess suggests that EPA clarify - preferably in the rule itself or alternatively in the preamble - that the lack of available infrastructure or capacity to gather and transport associated gas satisfies the meaning of technical infeasibility. In proposed section 60.5375(a)(1)(ii), EPA describes the separation flowback stage and requires that owners or operators "route the recovered gas from the separator into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an on-site fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve. If, at any time during the separation flowback stage, it is not technically feasible for a separator to function, you must follow the requirements in paragraph (a)(3)." EPA also states in section 60.53575(a)(2) that "all salable quality recovered gas must be routed to the gas flow line as soon as practicable. In cases where salable quality gas cannot be directed to the flow line due to technical infeasibility, you must follow the requirement in paragraph (a)(3)." Paragraph (a)(3) allows for owners and operators to "capture and direct gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion ... "

The language in the Proposed OOOOa Rule is substantially similar to language that was included in EPA's final rule "Oil and Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants," which addressed reduced emission completions for gas wells. However, in that final rule, EPA did not rely as heavily on the term "technical infeasibility" as the Agency has done in the current regulatory proposal. For instance, in the regulatory text for gas well completions in section 60.5375(a)(1), EPA refers to the term "infeasible," but does not modify the term with "technically." Additionally, in the final rule for gas well completions, EPA responded to comments on the availability of infrastructure to convey gas to market: EPA stated that " [w]e believe that owners and operators of gas wells subject to 40 CPR 60.5375(a) that require REC for a portion of the flowback period will exercise due diligence in coordinating the completion event with availability of a flow line to convey captured gas to market. However, there may be cases in which, for some reason, the well is completed and flowback occurs without suitable flow line available. In those isolated cases, we believe that 40 CFR 60.5375(a)(3) provides for gas not being collected and instead combusted or vented pursuant to that section. " The section that EPA refers to deals with the standards that apply to gas well affected facilities and requires that all salable quality gas be routed to a flow line and where that cannot happen that "[y]ou must capture and direct flowback emissions to a completion combustion device ... " Hess believes that the term "technical infeasibility" in the Proposed OOOOa Rule will create confusion and may inadvertently increase the burden for showing that a lack of infrastructure capacity satisfies the "infeasibility" determination. Hess therefore suggests that EPA alter the regulatory text of the final OOOOa Rule and include language in the preamble that is consistent with the Subpart OOOO gas well rule.

Response: See responses to DCN EPA-HQ-OAR-2010-0505-6787, Excerpt 32 and DCN EPA-HQ-OAR-2010-0505-6789, Excerpt 11.

Commenter Name: Cory Pomeroy, General Counsel
Commenter Affiliation: Texas Oil & Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-7058
Comment Excerpt Number: 57

Comment: Feasibility of routing recovered gas from a well completion flow back to a gas gathering system pipeline cannot hinge on an arbitrary distance from the well to that pipeline or any other threshold criteria. Each and every well presents unique circumstances related to reservoir characteristics, surface conditions and numerous technical and non-technical factors.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6787, Excerpt 32.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 62

Comment: EPA Should Not Base the "Technical Infeasibility" Analysis Solely on a Well Site's Proximity to Gathering Lines or Other Technology.

EPA has solicited "comment on criteria that could help clarify availability of gathering lines," given that this "is one consideration affecting feasibility of recovery of natural gas during completion of hydraulically fractured wells." To the extent that this request indicates that the agency is considering whether a bright-line proximity rule should determine whether an operator at a well site should be permitted to flare rather than use captured gas for a beneficial purposes, Commenters believe that considering claims on a case-by-case basis is a much better option than a numeric cutoff based on distance. A bright-line proximity test would ignore that "technical feasibility" and availability of gathering systems are multi-factor considerations. In order to aid in EPA's decision making, we provide the following information and sources of data.

First, in response to EPA's solicitation of "comment on whether distance from a gathering line is a valid criterion on which to base requirements for gas recovery," Commenters urge EPA not to use distance as the sole criterion to determine whether an operator may flare captured gas rather than use it for a beneficial purpose. EPA recognizes that the availability of gathering lines is not a simple question of distance; rather, there are "several factors that can affect availability of a gathering line including, but not limited to, the capacity of an existing gathering line to accept additional throughput, the ability of owners and operators to obtain rights of way to cross properties, and the distance from the well to an existing gathering line." A similar position is articulated in two recent analyses, by the North Dakota Petroleum Council Task Force and Three Affiliated Tribes Task Force (also in North Dakota), which found factors other than mere distance to have greater or equal influence on availability.

Furthermore, the availability of the capture technologies discussed above, as well as current state regulations, militates against any proximity-only or proximity-driven determination. As EPA stated in the Technical Support Document to the 2012 rule and repeated in the Technical Support Document to the Proposed Rule, "[t]he State of Wyoming has set a precedent by stating proximity to gathering lines for wells is not a sufficient excuse to avoid RECs unless they are deemed exploratory, or the first well drilled in an area . . . ." Where states have pushed industry for needed reductions and changes, such as with North Dakota's milestones and Wyoming's refusal to consider gathering line proximity as an excuse, operators have demonstrated their capability to adopt such measures and continue producing oil and gas profitably.

In light of these considerations, the case-by-case analysis identified above is a more appropriate mechanism for determining technical feasibility than a distance cutoff. Submissions by operators claiming the exemption should include the relevant data for determining the technical feasibility of their individual situations, which EPA or a state agency could consider as a basis for granting or rejecting a REC exemption. Distance alone does not provide the necessary information for such a determination.

To the extent that EPA considers gathering line proximity as one valid criterion going to technical infeasibility, there is a great deal of data available to the agency in setting this criterion. Three of the most detailed and promising sources—from two of the states with a great proportion of the oil wells subject to the rule—are the Texas Railroad Commission's digital map data on wells and pipelines and the North Dakota Industrial Commission's gathering line data and gas capture plans. The Texas Railroad Commission's mapping data is available online through a GIS viewer, to which members of the public may submit individual queries, and the raw data is available for purchase. The North Dakota Industrial Commission possesses two sources of information: (1) a database of gathering lines across the state, as submitted by operators and including geographic information and fluid transported; and (2) the gas capture plans submitted by well operators in advance of their completions and including the data described above. This data could inform EPA decisions, though all of it is not publicly available.

From the data readily available to the public, Commenters mapped North Dakota's wells, compressors, and processing plants to get a better sense of the wells' proximity to gas processing infrastructure. While GIS data on gathering lines were not available, one can assume that gathering lines occupy much of the distance between wells, compressor stations, and processing plants. Therefore, the distances presented here are longer than actual distance to gathering lines.

[Table 8: Distance of North Dakota Wells from Nearest Compressor Station]

From these data, one can see that the majority of North Dakota wells are within 10 miles of the nearest compressor station. Given that a vast number of gathering lines run between wells, compressor stations, and processing plants (nearly 10,000 miles, as of 2014, and rapidly growing), the true distance of these wells to the necessary collection and processing infrastructure is undoubtedly much less than ten miles.

In short, while a five-mile gathering line may not be economically feasible for a single well, it may be feasible if the pad has multiple wells. And while a gathering line longer than ten miles may not be feasible for a multi-well pad, it may be a feasible investment for several nearby pads. Other options for gas transport and use—such as trucking CNG to nearby processing plants, using the captured gas for local energy generation, and mini-gas-to-liquids operations— are feasible at greater distances, even for single wells. As described above, the technologies for CNG transportation and on-site and local uses of recovered gas are developing rapidly. If EPA chooses to use distance as a criterion for determining technical feasibility, it must not use it as the sole factor. Rather, it must require the simultaneous consideration of other factors that affect technical feasibility of gathering systems, such as geography, capacity, and rights-of-way. Additionally, EPA must require the consideration a groups of wells and as it relates to other forms of capture technology, such as use as a fuel source and trucking CNG to market.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6787, Excerpt 32.

Commenter Name: Richard A. Hyde, P.E., Executive Director
Commenter Affiliation: Texas Commission of Environmental Quality (TCEQ)
Document Control Number: EPA-HQ-OAR-2010-0505-6753
Comment Excerpt Number: 7

Comment: Considering the difficulty with control equipment availability and the severe price slump of natural gas and crude oil, the TCEQ recommends that some of the proposed time lines and compliance dates should provide more flexibility, with priority assigned to the largest emissions sources.

Response: Please see section VI.E.5 of the preamble to the final rule for a response to this comment.

Commenter Name: J. Jared Snyder
Commenter Affiliation: New York State Department of Environmental Conservation.
Document Control Number: EPA-HQ-OAR-2010-0505-6894
Comment Excerpt Number: 7

Comment: Deadlines, Availability & Other

EPA requested comment on applicability deadlines for the new green completion requirements for emissions at oil well sites. The DEC supports EPA's deadline of 60 days after the final rule is published in the federal register as a reasonable deadline.

Response: Please see section VI.E.5 of the preamble to the final rule for a response to this comment.

Commenter Name: Mike Gibbons, Vice President – Production
Commenter Affiliation: CountryMark Energy Resources, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-6241
Comment Excerpt Number: 52

Comment: As discussed above, we believe that our industry will require up to 24 months to fully meet compliance with this regulation. This is based on our belief that equipment will not be available for all owners/operators and qualified third-party companies will not have sufficient staff to meet the engineering and survey requirements.

EPA could utilize a metric such as total oil production coupled with the Gas to Oil Ratio (GOR) as a method to phase compliance requirements over the 24 month period. The GOR alone is not the right metric to develop a phase approach, but should also be considered with the oil production rate. Considering the oil production rate and GOR results in the highest impact wells being covered at the beginning of the implementation period and lower impact wells coming under the compliance requirements at the end of the 24 month period.

If the GOR is used, EPA should consider how the GOR changes over the lifecycle of a producing well. The GOR is typically at its highest point when a well begins production, and declines through the lifecycle of the well. We suggest that the phase-in of the compliance activities only apply to the GOR of wells at the time that compliance is required, and not the GOR at the beginning of the well production cycle (i.e. the final regulation is posed to the Federal Register 7/1/16 and a well is drilled or modified on 10/1/16, a phase-in schedule requires compliance on 4/1/17; the GOR should be evaluated on 4/1/17, not 10/1/16).

Response: Regarding the compliance timeline, see section VI.E.5 of the preamble to the final rule. Regarding the GOR exemption, see section VI.E.3 of the preamble to the final rule.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 77

Comment: Industry also lacks the necessary equipment to roll out REC requirements nationwide in such a short implementation window. EPA should create a compliance phase-in period of at least 6 months. This phase-in timeline will give operators the flexibility to meet new requirements for any RECs involving specialized equipment. If there is no phase-in period, the REC requirements will be particularly burdensome for small operators. The lack of supply will drive up REC costs, which will not be absorbed as quickly by smaller entities. And these small entities will almost certainly lack the purchasing power of larger operators, thereby making it difficult to obtain the needed equipment before the compliance period begins.

Response: Please see section VI.E.5 of the preamble to the final rule for a response to this comment.

3.10 Other Comments on Well Completions

Commenter Name: Ben Shepperd
Commenter Affiliation: Permian Basin Petroleum Association
Document Control Number: EPA-HQ-OAR-2010-0505-6849
Comment Excerpt Number: 81

Comment: Gas composition and volume. EPA has proposed two subcategories for wells, subcategory 1 which includes non-wildcat and non-delineation wells, or subcategory 2, which includes wildcat and delineation wells. These definitions are loose and make a number of assumptions about the consistency of geologic formations and the salability of the gas before it can even be analyzed. Instead of requiring that an oil well be categorized, the PBPA recommends that flaring simply be allowed as a REC option. The subcategory classification system for oil wells should be withdrawn.

Response: We disagree that the definitions for the categories are loose. Owners and operators know whether they are drilling delineation or wild-cat wells. This claim does not support not requiring REC for subcategory 1 where technically feasible.

Commenter Name: Ben Shepperd
Commenter Affiliation: Permian Basin Petroleum Association
Document Control Number: EPA-HQ-OAR-2010-0505-6849
Comment Excerpt Number: 84

Comment: 1. The REC requirements for oil wells should be withdrawn.

2. Alternatively, should EPA move forward with REC requirements for oil wells, flaring should be allowed as an option.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6849, Excerpt 80.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 7:55 PM; Public Hearing #1 - Denver, Colorado
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7337
Comment Excerpt Number: 255

Comment: I also request that the EPA remove technical feasibility exceptions. If the well cannot be completed with reduced emissions, it shouldn't be drilled, in the first place.

Response: The EPA disagrees with the commenter that the rule can or should prohibit a well from being drilled if a REC is infeasible. There are many situations where conducting a REC is technically infeasible and the final rule provides relief from requirements only in these instances. See also the response to DCN EPA-HQ-OAR-2010-0505-6789, Excerpts 11 and 12.

Commenter Name: Kari Cutting
Commenter Affiliation: North Dakota Petroleum Council (NDPC)
Document Control Number: EPA-HQ-OAR-2010-0505-6789
Comment Excerpt Number: 13

Comment: Due to the unique circumstances in North Dakota described above, EPA should accommodate additional exemptions for certain oil well completions.

In addition, EPA should adopt a grace period for well flowback in which emissions may be routed to a flare. This is because EPA's existing distinction between "initial flowback" and "separation flowback" is an illogical distinction without a difference. Many operators in the Bakken immediately flowback to a "flowback separator" during well completion before installing more permanent separation equipment at the site. However, EPA's Proposed NSPS OOOOa does not define "separator" and does not distinguish between flowback or production separation. Moreover, some well sites do not have clear initial and separation flowback stages like gas wells, and there may be wells in which the initial flowback stage is followed by directing flowback immediately into the production battery. EPA should offer more flexibility to meet the control requirements by allowing a grace period of at least 14 days during which operators may route emissions to a flare during the indistinguishable "initial" and "separation" flowback periods.

NDPC suggests that EPA amend its definition of "flowback period" to state that "[t]he flowback period ends when the flowback equipment is permanently disconnected." Importantly, flaring may be required for safe operations and maintenance until the flowback equipment can be removed. The date that gas can be separated and sent to a sales pipeline (start-up of production) is independent of the need to flare for safety or maintenance reasons during flowback.

Response: The final rule defines the startup of production as the end of the flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate or produced water. In the case that the initial flowback stage moves directly to production stage, there will be no requirements related to the separation flowback stage. The information available to the EPA indicates that although there are many factors involved, an operator is able to determine when a separator can be operated. Therefore, the rule requires the operator to operate the separator as soon as possible and we do not agree that a nominal 14 days for this period be included in the rule. The operator's responsibility to operate in a safe manner is not in conflict with the rule requirements as the rule currently allows for flaring at any point that the rule requirements cannot be met due to safety hazards. See also the response to DCN EPA-HQ-OAR-2010-0505-6960, Excerpt 15.

Commenter Name: J. Roger Kelley
Commenter Affiliation: Domestic Energy Producer's Alliance (DEPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6793
Comment Excerpt Number: 11

Comment: In addition, EPA should adopt a grace period for well flowback in which emissions may be routed to a flare. This is because EPA's existing distinction between "initial flowback" and "separation flowback" is an illogical distinction without a difference. Many operators in the Bakken immediately flowback to a "flowback separator" during well completion before installing more permanent separation equipment at the site. However, EPA's proposed regulations do not define "separator" and do not distinguish between flowback or production separation. Moreover, some well sites do not have clear initial and separation flowback stages like gas wells, and there may be wells in which the initial flowback stage is followed by directing flowback immediately into the production battery. EPA should offer more flexibility to meet the control requirements by allowing a grace period of at least 14 days during which operators may route emissions to a flare during the indistinguishable "initial" and "separation" flowback periods.

DEPA suggests that EPA amend its definition of "flowback period" to "The flowback period ends when the flowback equipment is permanently disconnected". Flaring may be required for safe operations and maintenance until the flowback equipment can be removed. The date that gas can be separated and sent to a sales pipeline (startup of production) is independent of the need to flare for safety or maintenance reasons during flowback.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6789, Excerpt 13.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 78

Comment: We request clarification from EPA on completion flowback. In some fields, operators will flow completion fluids directly into the production tank batteries. In these instances, how will the proposed rule apply the REC requirements?

Response: For developmental wells, the operator is required to have REC equipment onsite during the entire completion. It is the operator's responsibility to determine what portions of flowback are considered initial flowback and when a separator can be operated and separator flowback begins. The current practice of flowing directly to production tank batteries will only be allowed during what is defined in the rule as the initial flowback stage. Otherwise the operator must operate the separator unless it is technically infeasible to do so.

Commenter Name: Steve Henke
Commenter Affiliation: New Mexico Oil and Gas Association (NMOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6850
Comment Excerpt Number: 7

Comment: Based on member feedback, NMOGA does offer one request to proposed changes to NSPS OOOO and OOOOa., specifically, exception for inert gas venting during the separation flowback stage. NMOGA's recommendation is included in the excerpts below.

60.5375a(a)(3) You must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways ***or it is technically infeasible due to inert gas concentration.***

60.5375a(f)(2) You must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways ***or it is technically infeasible due to inert gas concentration.***

The two excerpts above imply all gas must be combusted if it cannot go to pipe for the reasons mentioned. Nitrogen foam may be used to complete a well, as is done for oil wells in the San Juan Basin in northwest New Mexico, and the initial gas quality "is not of salable quality." However, the gas at this time cannot be combusted due to the high nitrogen (N2) content. N2 is also an inert gas, and therefore it is technically infeasible to combust the gas. The proposed language in blue [boldface] is required so that in this specific situation, where gas cannot go to pipe for one of the acceptable reasons provided by EPA and also cannot be combusted due to technical infeasibility, the gas can be vented during the separation flowback stage.

Response: The EPA agrees with the commenter that the capture of inert gas from the gas stream would render the gas not of salable quality. However, the rule provides for other options of beneficial use, and if not technically feasible for those uses, then the recovered gas must be combusted. We do not believe that the entire gas stream would be non-combustible based on inert gas concentration, therefore, all recovered gases must be routed to the combustion control device except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 61

Comment: EPA Should Exempt Inert Gas Venting During Separation Flowback Stage

The language in §60.5375a(a)(3) and §60.5375a(f)(2) implies all gas must be recovered to a completion combustion device if it cannot be routed to pipe "except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterway when wells are in the separation flowback stage. Nitrogen foam may be used to complete a well, as is done for oil wells in the San Juan Basin in northwest New Mexico. In this situation, the operation of a separator may be feasible, but the initial gas quality "is not of salable quality" nor can the produced gas be combusted due to the high nitrogen (N2) content. N2 is an inert gas, and therefore it is technically infeasible to combust the gas. The proposed language is required to clarify that in this specific situation, where gas cannot go to pipe for one of the acceptable reasons provided by EPA and also cannot be combusted due to technical infeasibility, the gas can be vented during the separation flowback stage. Note that in addition to N2, the content of other inert gases such as CO2 or hydrogen sulfide (H2S) may also disallow the use of a combustion device due to high inert gas composition.

In addition, EPA apparently intended to allow venting of the noncombustible flowback gas but neglected to include it in the rule text language.

"… [EPA] are proposing an operational standard for subcategory 1 wells that would require a combination of gas capture and recovery and completion combustion devices …, with provisions for venting in lieu of combustion for … or for periods when the flowback gas is noncombustible." 80 FR 56630.

"…[EPA] are proposing an operational standard for subcategory 2 well completions … with provisions for venting in lieu of combustion for … or for periods when the flowback gas is noncombustible." 80 FR 56632.

Therefore, API recommends the following clarifications be added to the rule:

§60.5375a(a)(3) You must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways or it is technically infeasible due to inert gas concentration.

§60.5375a(f)(2) You must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways or it is technically infeasible due to inert gas concentration.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6850, Excerpt 7.

Commenter Name: Maria Pica Karp, Vice President and General Manager, Chevron Government Affairs
Commenter Affiliation: Chevron U.S.A. Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6929
Comment Excerpt Number: 14

Comment: Recordkeeping: The paperwork and recordkeeping burden on the existing REC gas well program has proven expensive, and it does not appear that EPA has examined or utilized any of the REC reports. Instead of the REC-PIX program and extensive records regarding hourly flows, the Greenhouse Gas Reporting Program should be the tool for reporting emissions from RECs.

Response: The EPA disagrees with the commenter in that the recordkeeping burden for the gas well program is overly burdensome. The EPA also disagrees that the Greenhouse Gas Reporting Program is the appropriate place for reporting compliance with OOOOa, as not all operators have to report through GHGRP.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 67

Comment: Even if EPA somehow is able to justify the additional emissions benefits by making standard industry practice a regulatory requirement, the rule should be amended to avoid potentially overlapping requirements between NSPS OOOO and OOOOa. As written, the rule appears to set up different compliance periods for both oil and natural gas well completions. These should be consistent. In addition, we recommend the proposed rule offer flexibility to operators on the compliance reporting schedule, rather than dictate the timeline in the final rule.

Response: Because subpart OOOO applies to sources constructed, modified or reconstructed on or prior to September 18, 2015 and subpart OOOOa apply to those thereafter, there are no overlapping requirements. The EPA disagrees that there are different compliance periods for the completion requirements. Based on the date of the completion, a given well completion will be either subject to OOOO or OOOOa. Further, the rule does not set timelines for reporting requirements and is based on the operator including the completion in the next annual report submitted by the operator. It is the operator's discretion when the annual report will be submitted.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 59

Comment: EPA Should Ensure Provisions Requiring Capture and Beneficial Use of Completion Emissions are Rigorously Applied.

As in the 2012 VOC rule with respect to gas wells, EPA includes in the Proposed Rule an exemption for certain classes of oil wells from the REC requirements. Specifically, EPA proposes the following requirements:

During the separation flowback stage, . . . [r]oute the recovered gas from the separator into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an on-site fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve. If it is technically infeasible to route the recovered gas as required above, follow the requirements in paragraph (a)(3) of this section.

The requirements in paragraph (a)(3) provide that in such a "technically infeasible" scenario, the operator "must capture and direct recovered gas to a completion combustion device," with certain additional exceptions. Toward better defining the standard of technical feasibility, EPA has solicited comment "on criteria that could help clarify availability of gathering lines," as well as "any other factors that could be specified in the NSPS for requiring recovery of natural gas from well completions."

As stated, we strongly support the Proposed Rule's REC requirement at oil wells, which were not addressed in the 2012 VOC rule. As currently stated in the Proposed Rule, however, the "technically infeasible" exemption could detract significantly from the overall value of this standard if not limited narrowly. The swiftly increasing production of oil (along with associated natural gas) in the Bakken shale formation demonstrates the need for a strong rule. Production in the Bakken hit an all-time high in July 2015, and the number of producing wells reached an all-time high in August 2015. Tight oil formations, like the Bakken, produce very high initial rates of oil and associated gas, which then decline rapidly. For instance, an "example well" may produce 340 million cubic feet per day of associated natural gas in the first month of production. Given this quickly expanding production and resulting potential for high initial emissions, it is vital that the Proposed Rule's REC requirements apply rigorously. To this end, Commenters provide data on the factors for which EPA has solicited input and urge EPA to ensure maximum gas capture, to improve compliance and enforcement and for other reasons described below.

Response: See section VI.E.2 of the preamble to the final rule for a discussion on this topic. Also see the response to DCN EPA-HQ-OAR-2010-0505-6789, Excerpts 11 and 12.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 60

Comment: Operators Have Many Options To Use Captured Gas.

In the proposed rule, EPA has recognized that capture and beneficial use of natural gas is far preferable to alternatives that involve flaring. Consistent with that understanding, Commenters urge EPA to tightly limit the provision that operators of hydraulically fractured oil wells may flare associated natural gas where routing to a gathering line or collection system is "technically infeasible." As currently crafted, this provision is vague and runs counter to the improvements EPA seeks to establish within the oil and gas industry. Furthermore, it is very rarely necessary. EPA has identified *four* separate options for utilizing gas captured through RECs: operators may (1) "[r]oute the recovered gas from the separator into a gas flow line or collection system; (2) "re-inject the recovered gas into the well or another well;" (3) "use the recovered gas as an on-site fuel source;" or (4) "use the recovered gas for another useful purpose that a purchased fuel or raw material would serve."

Even if an operator is unable to route the natural gas to a gathering line, or if no such infrastructure exists near the oil well site, there are three other options available for operators to use gas captured during the REC, including one that is broadly defined to cover any "useful purpose that a purchased fuel or raw material would serve." Given the broad scope of this language and the available technologies we describe below, EPA must ensure that operators rigorously evaluate these alternatives as part of compliance with REC requirements. As the U.S. Department of Energy discussed in a 2014 analysis of infrastructure in the Bakken, these uses for gas other than routing to a gathering line or flaring are becoming even more feasible as industry invests "in technology to use the natural gas produced from newly drilled wells until output stabilizes and gathering lines can be completed. Some technologies include converting natural gas to liquid fuels, mobile [natural gas liquids (NGL)] extraction, producing fertilizer from wellhead natural gas, or developing onsite electrical generation." Recent examples include a process in which an operator could "capture gas at the wellhead, strip out valuable NGLs, compress it into [compressed natural gas (CNG)]," which could then be used as fuel source, and "small-scale gas-to-liquids" units, which could be brought to wellheads where no gathering infrastructure exists. These technologies demonstrate that even if a well is unable to connect to a gas gathering system, there are many feasible options in addition to flaring.

Moreover, the costs of these technologies are reasonable. A recent Carbon Limits study commissioned by the Clean Air Task Force examines the options for capture, transport, and use of associated natural gas as alternatives to flaring. The study finds three options in particular are proven and in-use in tight oil formations: NGL recovery, CNG trucking, and gas-to-power generation. Carbon Limits describes case studies of existing installations of these technologies, where they are making money for companies that use them. Even where there is a net cost involved, that cost is small considering the large amount of pollution that is prevented when these technologies are used. The Carbon Limits study modeled the economic costs and environmental benefits of these technologies at typical tight oil wells. The results of this cost analysis are summarized in the Table 7. At nearly all wells, one or a combination of several of these technologies can be utilized. NGL recovery and gas to power (for local loads) can be suited for remote wells, while CNG trucking is economically feasible at wells that are relatively close to a processing plant or other point where gas can be put into the pipeline system (20-25 miles or less).

[Table 7: Cost Analysis of Alternatives to Flaring Associated Gas in Tight Oil Formations]

Current state initiatives and regulations further demonstrate that operators are increasingly capable of using capture technologies to reduce flaring. As EPA stated in the Technical Support Document to the 2012 NSPS rule and repeated in the Technical Support Document to the Proposed Rule, "[t]he State of Wyoming has set a precedent by stating proximity to gathering lines for wells is not a sufficient excuse to avoid RECs unless they are deemed exploratory, or the first well drilled in an area . . . ." For operators in the Bakken formation, North Dakota set a series of milestones for reducing flaring of associated gas: 26 percent by October 2014; 23 percent by January 2015; 15 percent by January 2016 and 10 percent by October 2020. To achieve these milestones, the state requires operators to submit a "gas capture plan" in its application to drill and will impose restrictions on a well's production if an operator does not meet the applicable milestone.

Where states have pushed for these needed reductions and changes, operators have demonstrated that they largely have the capability to reduce flaring and use this captured gas for beneficial purposes, even as production has increased. For example, North Dakota operators have greatly increased their capacity to collect, transport, and process natural gas over the last several years. As the Department of Energy recently summarized on North Dakota's progress, "nearly $6 billion has been invested by the natural gas capture industry since 2006. Since that time, the industry has built more than 9,555 miles of gas gathering pipeline, 1.259 bcf/d of gas processing, and increased export capacity for residue gas and NGLs." Processing capacity jumped five- fold between 2006 and 2013; by the end of 2015, processing capacity in North Dakota will reach 1.6 billion cubic feet per day, "an amount on par with total gross withdrawals." In fact, the most recent production and processing data from the state suggest that the processing capacity already matches production: according to the North Dakota Pipeline Authority, "North Dakota currently has twenty-four natural gas processing/conditioning plants operating, with the capability to process roughly 1.6 BCFD," or 48 billion cubic feet per month, while the state's natural gas production was 48.11 billion cubic feet in September 2015.

The actions of individual operators also demonstrate the achievability (and profitability) of gas capture technologies and reductions in flaring. Individual North Dakota companies have increased their collection and processing capacity to reduce flaring and enhance revenue at a rate significantly above the statewide milestone. For example, Whiting Petroleum captured more than 85 percent of its associated natural gas in the first quarter of 2015, well above the current state milestone of 77 percent. The company, which operates about 12 percent of the state's nearly 13,000 active oil and gas wells, intends to improve on this capture rate through the expansion of its processing capacity. A review of Whiting's facility locations demonstrates that the company has apparently grouped its wells and processing plants near each other, thereby increasing the feasibility of capturing and selling associated natural gas.

Accordingly, operators have a variety of options available to them for using gas captured through RECs. If pipeline infrastructure exists on-site or nearby, they can direct it there for eventual sale. Otherwise, they can put it to any number of other uses, including (but not limited to) those described above. Flaring is, in the vast majority of cases, an unnecessary and wasteful alternative to more productive options. EPA should therefore either remove the exemption for flaring in the event of "technical infeasibility" or strictly limit the exemption according to the principles described in the following subsection.

173 80 Fed. Reg. at 56,665 (proposed 40 C.F.R. § 60.5375a(a)(1)(ii)). We note that this language may not fully reflect EPA's intent that all of these options must be technically infeasible before an owner or operator may send the gas to a completion combustion device. EPA should clarify this language to make it consistent with its intent as stated in the preamble. *See* 80 Fed. Reg. at 56,631 ("If, during the separation flowback stage, it is technically infeasible to route the recovered gas to a flow line or collection system, re-inject the gas or use the gas as fuel or for other useful purpose, the recovered gas must be combusted.").

Response: See section VI.E.2 of the preamble of the final rule for more detail regarding this issue.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 61

Comment: EPA Must Add Provisions Requiring Operators to Demonstrate the "Technical Infeasibility" of Each of the Options and Consideration of Such Claims on a Case-by-Case Basis.

A narrowly defined "technical infeasibility" exemption from the REC requirement should include in the final rule provisions requiring operators to demonstrate adequately, through the submission of documentation and supporting information, that each one of the four options is technically infeasible. EPA and state agencies could then consider such claims on a case-by-case basis.

Given that EPA has solicited comments on certain aspects of the technical infeasibility exemption, including those helping to clarify the availability of gathering lines and the types of oil wells not capable of performing a REC, EPA should add provisions to the final rule that require notification, submission of supporting information, and consideration by EPA and state agencies of claims of technical infeasibility. Such case-by-case considerations could serve to provide the agency and the public with needed information, help to ensure that operators are fully considering environmentally preferable alternative options, and give additional information to EPA on what factors constitute true technical infeasibility.

A useful model for such a new provision is North Dakota's gas capture report. Prior to completing a well, operators in North Dakota must submit a report detailing and supporting certain factors, including:

- An affidavit signed by a company representative indicating that the operator met with gas gathering companies;
- A detailed gas gathering pipeline system map, including the proposed route and tie in point to connect the well to an existing gas line;
- Information on the existing line, to which operator proposes to connect including current daily capacity, throughput, and plans for expansion;

- Anticipated date of first production, with oil and gas rates and duration (for all wells being completed, if on a multi-well pad);
- Amount of gas the operator is currently flaring across the state; and
- Alternatives to flaring available to and/or planned by the operator.

In addition to these factors, the operator could provide the information demonstrating what factors specifically make routing, reinjection, use, or other alternatives to flaring technically infeasible, such as exceptional geography, reasonably unforeseen circumstances, or factors beyond the control of the operator. This would help ensure that flaring only occurs when all other options have been thoroughly explored and rejected for justifiable reasons.

An appropriate location in the Proposed Rule for this submission and consideration of technical infeasibility claims would be under the existing notification requirements of 40 C.F.R. § 60.5420a(a)(2). The Proposed Rule currently states:

If you own or operate a well affected facility, you must submit a notification to the Administrator no later than 2 days prior to the commencement of each well completion operation listing the anticipated date of the well completion operation. The notification shall include contact information for the owner or operator; the API well number; the latitude and longitude coordinates for each well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the planned date of the beginning of flowback. You may submit the notification in writing or in electronic format.

EPA could amend this provision to add new subparagraph (a)(2)(iii), with potential requirements as follows:

If you intend to claim that it is "technically infeasible" to route, re-inject, or use recovered natural gas for a useful purpose, as specified in §60.5375a(a)(1)(ii), you must submit a notification to the Administrator no later than 30 days prior to the commencement of each well completion operation. The notification shall include the information required by paragraph (a)(2)(i), as well as: the reasons for the claim(s) of technical infeasibility; and detailed information and evidence supporting the claim(s), including, but not limited to, the name and location of the three closest gathering systems, capture and reuse technologies considered, the anticipated oil and gas production rates (for all wells being completed, if on a multi-well pad), and the amount of gas you are currently flaring at other operations. You must submit the notification in electronic format.

The primary differences between this notification and the existing notification provision, aside from the additional information required, are that the operator must submit the notification for claiming the exemption at least 30 days prior to completion and that the notification must be in electronic format to facilitate EPA's consideration and public accessibility. We urge EPA to make these requests, and EPA's ultimate determination, transparent and publicly available.

In connection with this new provision, EPA should amend the existing language of the exemption. While it is clear in the preamble to the Proposed Rule that the exemption applies where "it is technically infeasible to route the recovered gas to a flow line or collection system, re-inject the gas or use the gas as fuel or for other useful purpose," the language of the Proposed Rule differs from the preamble and may confuse operators. The Proposed Rule currently states "[i]f it is technically infeasible to route the recovered gas as required above," without also including "re-inject the gas or use the gas as fuel or for other useful purpose." To make it clear that an operator must demonstrate all of the options to be technically infeasible, EPA should change the language of the exemption to read:

If it is technically infeasible to route the recovered gas to a flow line or collection system, re-inject the gas or use the gas as fuel or for other useful purpose, as required above, follow the requirements in paragraph (a)(3) of this section.

A case-by-case approach would place the burden of proof on those claiming the exemption and provide EPA with additional information on the availability of recovered gas capture and routing opportunities and alternatives, and increase public disclosure and transparency. Short of removing the exemption altogether, this approach (in conjunction with clarification that flaring is only permitted if four primary options are infeasible) would significantly improve the means by which EPA can reduce flaring, protect air quality, and prevent waste, and so meet its section 111 obligations.

Response: See section VI.E.2 of the preamble to the final rule for more detail regarding this issue.

Commenter Name: J. Young
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2010-0505-6469
Comment Excerpt Number: 12

Comment: We urge you to improve the proposed rules to include:

Requiring oil and gas companies to use or bring to market captured gas, rather than flare it, unless truly extraordinary circumstances make flaring unavoidable.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5288, Excerpt 6.

Commenter Name: Jennifer Cassel, Staff Attorney
Commenter Affiliation: Environmental Law & Policy Center
Document Control Number: EPA-HQ-OAR-2010-0505-6994
Comment Excerpt Number: 3

Comment: Specifically, as delineated by our colleague Earthworks in their separate comments on this proposed rule, the draft rule should be revised to include:

- Mandates that oil and gas companies use or bring to market captured gas, rather than flare it, unless truly extraordinary circumstances make flaring unavoidable.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5288, Excerpt 6.

Commenter Name: Nick Lund, Senior Manager, Conservation Programs
Commenter Affiliation: National Parks Conservation Association (NPCA)
Document Control Number: EPA-HQ-OAR-2010-0505-7060
Comment Excerpt Number: 5

Comment: Requirements for Use or Capture of Gas: Oil and gas companies should be required to use or bring to market captured gas, rather than flare it, unless truly extraordinary circumstances make flaring unavoidable. Studies show that up to 40% of methane on the Bakken Formation in North Dakota is vented, an act that produces no royalties for the American public. In 2014, NPCA documented examples of venting and flaring on the Bakken Formation near Theodore Roosevelt National Park (http://maps.fractracker.org/latest/?appid=ecba3b12664c425eb56525df949f74f6&webmap=b5322726d40649c1bf6d9a1f4184e32c). Vented gas also contributes to a large methane plume in the Four Corners area, home to several of our most iconic national parks.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5288, Excerpt 6.

Commenter Name: John Quigley
Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)
Document Control Number: EPA-HQ-OAR-2010-0505-6800
Comment Excerpt Number: 19

Comment: Methane Emissions from Oil Wells

The proposed NSPS amendments do not include requirements for the control of methane emissions from oil wells after the well completion has been performed and the well is put into production.

The DEP recommends that EPA address methane emissions from oil wells after the wells are put into production by requiring owners or operators to capture the methane gas or flare it if capturing the gas is technically infeasible. Enclosed combustion devices such as enclosed flares should be required for all permanent flaring operations at a wellhead or facility, when feasible.

Response: The EPA appreciates the information provided by the commenter. Methane emissions from oil wells after the wells are put into production is not covered in OOOOa. The EPA is seeking additional information on this topic through the upcoming Information Collection Request.

Commenter Name: Laredo Petroleum
Commenter Affiliation: Laredo Petroleum
Document Control Number: EPA-HQ-OAR-2010-0505-6474
Comment Excerpt Number: 9

Comment: If natural gas is going to sale, is that the end of the separation flowback even if the flowback equipment is still being used? Or is it when the normal production equipment is being used and the temporary equipment is taken out of service? Separation flowback is defined on page 56611, column 1, under Section VII F. Well Completion. The manner in which this is written will cause confusion since first production is often considered when gas goes to sale but this could be a different date than when the temporary equipment is removed.

Response: The rule defines the end of separation flowback stage to be either at the startup of production, or when the well is shut in and permanently disconnected form the flowback equipment. The rule defines the startup of production to be the beginning of initial flow following the end of flowback when there is a continuous recovery of salable quality gas and separation and recover of any crude oil, condensate or produced water. The end of separation flowback is when the normal production equipment is being used and the temporary equipment is taken out of service.

Commenter Name: C. William Giraud
Commenter Affiliation: Concho Resources Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6847
Comment Excerpt Number: 8

Comment: The currently proposed definition for hydraulic fracturing is overly broad and should be amended to make clear which operations are covered by the proposed regulation. As an alternative definition, which would provide clarity for both regulators and the regulated community, Concho recommends the following: "Those operations conducted in an individual wellbore designed to increase the flow of hydrocarbons from the rock formation to the wellbore through modifying the permeability of reservoir rock by applying fluids under pressure to fracture it. Hydraulic fracturing does not include enhanced secondary recovery such as water flooding, tertiary recovery, recovery through steam injection, or other types of well stimulation operations such as acidizing."

Response: The EPA does not agree that the definition of hydraulic fracturing in the rule is overly broad. We intend to include operations that would increase the flow of hydrocarbons to the wellhead, and therefore, the operations described by the commenter would be included.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 67

Comment: EPA Should Not Require Tracking Attempts To Connect To A Separator For Flowback That Never Leaves The Initial Flowback Stage.

As described in Section 22.2.6, API requests that EPA clarify the recordkeeping requirements outlined in §60.5420a(c)(1)(iii)(A) for tracking attempts to connect to a separator as only being applicable during the separation flowback stage (after initial flowback, they are hooked up to a production system). For well completion operations that remain in the initial flowback stage, a separator is not required and, therefore tracking attempts to connect to one is not applicable.

Response: The EPA believes that all circumstances preventing the recovery of gas using a separator cannot be known in advance, and therefore, for development wells, we continue to require that a separator be present onsite and that the operator document attempts to use the separator during the completion event.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 7:55 PM; Public Hearing #1 - Denver, Colorado
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7337
Comment Excerpt Number: 235

Comment: In terms of the green completions, we request the EPA remove the technical feasibility exception. We believe it invites poor design or even creates a loophole that encourages a deliberate designing away of the regulatory applicability. We believe that if the well cannot be completed with the standards set forth, it should not be drilled.

Response: The EPA disagrees with the commenter that the rule can or should prohibit a well from being drilled if a REC is infeasible. There are many situations where conducting a REC is technically infeasible and the rule provides relief from requirements in these instances.